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NATIONAL POWER SURVEY

FEDERAL POWER COMMISSION — 1964 PART I

GUIDELINES FOR GROWTH OF THE ELECTRIC POWER INDUSTRY

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CITY OF COLORADO SPRINGS DEPARTMENT OF PUBLIC UTILITIES • CENTRAL ILLINOIS PUBLIC SERVICE CO • MIDWEST ELECTRIC CO

OBJECTIVES OF THE SURVEY

It is the earnest hope of the Federal Power Commission that the National Power Survey, to which many outstanding people from all segments of the electric power industry have made important contributions, will set a standard and be a guide for the future planning of the industry. What we have set forth is not a blueprint but an illustration of a possible pattern of efficient development. We hope it will excite interest in the many opportunities for savings which should be explored.

We have also suggested that the American consumer should benefit from these savings in the form of lower rates and steady improvement in the already very high quality of service.

The goal we propose is an electric power industry animated by a broad and bold vision of its role in contributing to the growth and welfare of the Nation's economy. We have tried to suggest an outline for the coordinated growth of the industry in the future which will attain that objective.

To make this goal a reality will require cooperation among the men responsible for management of the power systems throughout the Nation. It will require that they concentrate their efforts on realizing and sharing equitably the enormous potential benefits of a truly integrated system of power supply embracing all segments of the industry and every State in the Nation.

Joseph C Swidler

Joseph C. Swidler, *Chairman.*

David S. Black

David S. Black, *Vice Chairman.*

Lawrence J. O'Connor, Jr

Lawrence J. O'Connor, Jr., *Commissioner.*

Charles R Ross

Charles R. Ross, *Commissioner.*

October 23, 1964.

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PREFACE

On January 24, 1962, Chairman Joseph C. Swidler first announced the purpose of the Federal Power Commission to conduct a national power survey. President John F. Kennedy, in his Message on Conservation to the Congress of the United States, delivered February 28, 1962, expressed his endorsement of the proposal in the following terms:

> The ability to make long-range plans for the expansion of our Nation's electric power supply required by constantly growing power needs will be enhanced by a comprehensive nationwide survey to be undertaken by the Federal Power Commission. Under existing authority contained in the Federal Power Act, the Commission will project our national power needs for the 1970's and 1980's and suggest the broad outline of a fully interconnected system of power supply for the entire country. This information will encourage the electric power industry—both private and public—to develop individual expansion programs and intertie systems permitting all elements of the industry—and more importantly the consumers—to benefit from efficient, orderly planned growth. *I urge favorable action on the request for adequate funds to initiate this study of the Nation's power needs for the next 20 years.*

The Congress has made provision in successive budgets for the required funds.

The Report was prepared by the members of the Federal Power Commission and its staff. The staff work was carried out under the direction of F. Stewart Brown, Chief Engineer and Chief of the Bureau of Power. The members of the staff who made major contributions to the Survey are listed in the acknowledgments at the end of the report.

The National Power Survey on which this report is based was conducted in cooperation with all segments of the electric power industry. The Commission wishes to express its profound gratitude to the many executives and technical experts throughout the country who have given unsparingly of their time and effort. They are too many to name here, but we express particular indebtedness to the advisory committees, and especially the Executive Advisory Committee, of which Philip Sporn was Chairman and G. O. Wessenauer was Vice Chairman, and the General Technical Advisory Committee headed by Robert Brandt as Chairman and Charles Almon as Vice Chairman. As an illustration of the seriousness with which the advisory committees undertook their work and the extent of their contributions, the Executive Advisory Committee met with the Commission in Washington on 18 separate occasions. The members of all the committees are listed in the acknowledgments at the end of the report.

Notwithstanding our indebtedness and gratitude to the advisory committees, the Commission alone takes responsibility for the Survey Report.

Howard Morgan was a member of the Commission during the initiation and early programming of the Survey.

The Commission notes with sorrow the death on August 4, 1964, of Commissioner Harold C. Woodward, who helped to encourage and guide the work of the Survey. We also note with regret the death on April 6, 1963, of Dr. Paul J. Raver, who contributed greatly as a member of the Executive Advisory Committee in the formative stages of the Survey.

INTRODUCTION—BACKGROUND AND HIGHLIGHTS OF THE SURVEY

The electric utility industry of the United States stands at the threshold of a new era of low-cost power for all sections of our country. Many exciting new technological developments point the way. Larger and larger machines are being built which can generate electricity at progressively lower costs. These huge power plants burning fossil fuels are presenting a moving target for nuclear power plants which nevertheless are rapidly becoming more and more competitive. Extra-high-voltage (EHV) transmission lines can now move power economically for many hundreds of miles. EHV transmission has thus greatly enlarged the marketing area for large blocks of low-cost generation and has also increased the long-standing advantages of interconnecting power systems into power pools covering ever broader geographical areas.

The Nation's rapidly expanding use of electricity is expected to more than double and perhaps triple by 1980, and the physical plant of the industry will show corresponding growth. This large growth will give the industry an opportunity, assuming adequate research and development, to incorporate the many major technological advances into these new facilities. Consumers and the industry alike stand to gain if duplication of facilities is eliminated and this huge cost of more than $100 billion is invested in equipment which will meet the test of maximum efficiency.

The National Power Survey is a major undertaking by the Federal Power Commission, in cooperation with advisory committees drawn from all segments of the electric power industry, to give greater impetus to the trend toward integration of the Nation's power systems. The Survey suggests how all of our electric power systems can move from isolated or segmented operations, and from existing pools of limited scope, to participation in fully coordinated power networks covering broad areas of the country. In time, when justified economically, all the electric systems in the entire nation may be joined in a single interconnected network.

The National Power Survey was undertaken by the Commission because the many technological opportunities for further coordination of the Nation's 3,600 electric power systems suggested the need for broader planning of the coordinated growth of the industry than had yet been attempted. The Survey represents the first comprehensive study of the industry as a whole, covering the entire Nation and all ownership segments. The Survey suggests possibilities for further coordination in planning the large expansions of our power systems in the decades ahead while retaining the initiative of a pluralistic ownership pattern. In our opinion the technology of large scale generating stations and extra-high-voltage transmission interconnections has now reached the stage where closer coordination of the construction plans and operations of individual systems in the industry is highly feasible and necessary if the consuming public is to receive the benefits of lower cost electricity which our technology now makes possible.

A major purpose of the Survey is to point out possible patterns of expansion that may result in reduced costs and to indicate the order of magnitude of these savings. The Survey thus is encouraging the industry to initiate broader regional and interregional planning in which all ownership segments can plan and build facilities to meet their combined needs to the mutual advantage of themselves and their consumers. In short, the Survey was conducted by the Commission as the most effective means of carrying out the provisions of section 202 (a) of the Federal Power Act which directs the Commission to "promote and encourage . . . interconnection and coordination" of electric utility systems for . . . "the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources . . ."

The importance of the congressional mandate to the Commission to encourage interconnections has never been greater than it is today. The swift march of technology makes the opportunity for progress toward a fully coordinated power supply network not remote but immediate. The challenge to the industry is the speedy adoption of the broad range of technological advances in the construction of the facilities required to meet the loads of tomorrow.

The industry's past achievements, which have made it by far the largest and among the most efficient sources of electric power supply in the world, give us every reason to expect that this new challenge will also be met.

The National Power Survey is confined to the electric power industry and thus tends to emphasize the opportunities for growth in the use of electricity in the decades ahead without a similar emphasis on the growth potential of natural gas or other forms of energy. The Commission from its own regulatory experience is, of course, aware that a similar pattern of growth could be projected for the natural gas industry, which has had a spectacular growth since World War II, and we wish to emphasize that the Commission does not in any way mean to imply a preference for one form of energy over another. On the contrary, as the Survey Report makes clear, the American consumer will be the final judge as to the precise share each form of energy will supply in our growing energy market. We all stand to gain from the healthy competition which is developing as the electric power industry and the natural gas industry both strive to improve their service and reduce their rates.

We emphasize that the future patterns of the Nation's power systems depicted in the Survey Report are not intended as blueprints, because no one can foresee the many changes in technology, operating conditions, or market potential that may occur in the years ahead. What we have set forth is an illustration of a possible pattern of efficient development. Our purpose is to excite interest in the many opportunities for savings that should be explored, rather than to propose any final answers. The Power Survey is intended as the beginning, not the end, of planning for the best possible power system of the future.

The Survey could not have been conducted without the public-spirited assistance of all segments of the industry and of other governmental and private agencies. This assistance was channeled through advisory committees created to advise the Commission on all aspects of the Survey. The committees included an Executive Advisory Committee and a General Technical Advisory Committee, special technical committees on transmission and interconnection, power requirements, generating stations, fuels, distribution, a legal advisory committee, and regional advisory committees.

The membership of all these groups included top executives and outstanding engineers, economists and lawyers from every branch and segment of the industry. Twenty-four committee reports have been published. These reports, many of which represent the best in advanced thinking on industry problems, in themselves are a major contribution to industry planning. They were helpful building blocks for the Commission's own Report. The committee memberships are listed in the acknowledgments at the end of the report, and the technical reports prepared by the Committees are published in a separate volume as a part of the Survey Report.

While these Advisory Committees have been invaluable to the Commission in the conduct of the Survey, their members are not responsible for any statement or conclusion in the Report. The Survey Report reflects innumerable helpful comments from our advisors, but none of them necessarily agrees with the many comprehensive conclusions.

The Power Survey Report was prepared by the Federal Power Commission and its staff and the Commission assumes full responsibility for the exposition, analysis, and conclusions of the Report. Nothing stated in the Report, however, is to be construed as Commission approval, disapproval, or recommendation of any particular project. The focus of the Report is on general lines of growth and power system development.

One of the most encouraging aspects of the National Power Survey is the manner in which representatives from all segments of the industry worked together to achieve positive results. The committee discussions and the reports in which the committee members joined have contributed to the industry's thinking and oriented its current planning toward greater coordination and cooperation among all sectors of the industry. The high degree of unanimity achieved within the various committees, all of them broadly representative of the elements of the industry, is in itself a demonstration of the broad range of common problems and the ability of industry representatives to work together to solve them.

One important immediate byproduct of the Survey has been an increased awareness of the need for the electric power industry to devote more manpower and money to joint projects for research and development of the technology to make the pace of progress ever swifter.

A comparison of the present Survey Report with the first "national power survey" begun by the Federal Power Commission in 1935 is illuminating. A final report was never issued, but in an Interim Report (Power Series No. 1, 1935) the Commission suggested that a future report "of the highest public interest" should deal with "improving the interconnection and coordination of existing power facilities." In support of such a study the 1935 Interim Report referred to the growth of interconnections as being "relatively haphazard, handicapped by intercompany rivalries and prejudices and by artificial barriers, such as State lines, prohibitory laws and a lack of uniformity in tax laws in adjoining communities." Fortunately, a good part of that indictment has been erased by the industry's progress in building interconnections during the past 30 years; yet even today many individual systems are subject to the same criticisms.

The early decades of this century witnessed the swift discovery of new uses of electricity and the unparalleled growth in the Nation's material and living comfort which these uses helped to make possible. Beginning in the 1930's the rural electrification movement accelerated the coverage of the outlying country areas so that today more than 98 percent of American farms are served by electricity, as high a percentage as anywhere in the world. Today, virtually every American home, business and community, however small, enjoys, and is vitally dependent upon, this most versatile of all forms of energy.

The phenomenal growth in the use of electricity in the United States, which on the average has doubled every decade for its 80-year history, is due in large part to the fact that the industry's technological progress has made electricity one of the best bargains available. The long-term trend of electric rates has been downward even in the face of inflation. In perspective the industry has set a high standard in meeting the Nation's power needs.

The goal of the Survey is to help continue and if possible accelerate the trend of lower unit costs which promotes increased use of electricity.

The particular means of achieving greater economy upon which the Survey has focused is for power systems to plan together for cost reductions on a more comprehensive basis than has yet been undertaken. Planning has always been a tool of utility management on an individual company basis. In some areas the planning unit has become the area pool. In others informal coordination arrangements have served to broaden the planning perspective. We believe these approaches should on the one hand be broadened further to include all areas of the country and the systems of all segments of the industry, and on the other hand should be intensified to include more complete coordination in the construction of new facilities as well as their operation.

The Survey makes clear that the manner in which the Nation's 3,600 separate power systems plan and build for the future is of national concern. All generation and transmission facilities, whether owned by private, cooperative, Federal or other public agencies, should be planned and built as part of large coordinated power networks to achieve the lowest cost of bulk power supply. The economies of scale in large generating units coupled with low-cost energy transportation suggests that individual power systems should join together in constructing new capacity either through joint projects or by staggering their construction programs. Diversity in load patterns offers additional opportunities for capacity savings through interchange arrangements over broad areas.

These considerations point up the Nation's interest in encouraging every power generating system to look far beyond its own service areas in its planning of new capacity and of interconnections for capacity savings. Planning to coordinate the investments in new facilities and the operation of all of the power systems over broad areas of the country is a must if we are to achieve the objective set forth in the Federal Power Act of "an abundant supply of electric energy throughout the United States with the greatest possible economy." The Nation can afford no less.

Growth in power consumption and closer coordination of power systems are the twin ingredients in the formula for reducing future power costs. Large-scale plants and other facilities which make full use of the new technology cannot be built without increased demands for power which will justify large additions to capacity and more intensive use of existing facilities. The Survey stresses the advantages of coordinated growth. Growth and coordination are interrelated, and we recognize that a large increase in per capita use of electricity by 1980 is vital to achieving the major savings which the Survey projects.

The Nation has a large stake in the electric utility industry's continued progress toward making the promise of the new technology a beneficent reality. Our total electric power bill in 1963 was approximately $14 billion. By 1980 Americans may be using nearly three times as much electricity but paying only about twice as much—about $30 billion a year—provided the industry continues to achieve net reductions in unit costs in the face of increased cost of labor, land, equipment and materials.

At stake by 1980 are possible savings of as much as $11 billion a year to the American consumer. Much of these savings will result from the lower unit costs brought about by growth in loads but the rate of growth will in turn depend on reduced unit costs and reduced rates that will encourage greater use, a cycle of continuously interacting cause and effect.

By 1980, the requirements for fuels of all kinds for our electric systems, expressed in terms of coal equivalent, may be as much as 900 million tons a year. Even a 5-percent improvement in generating efficiency will save 45 million tons a year and thus add measurably to the life of our limited low-cost fossil fuel supplies which will continue to be needed while we perfect the processes of nuclear fission and fusion for production of electricity.

Any study of our Nation's future energy needs must take into consideration that our population is growing rapidly and that our dependence on energy is increasing as we continue to raise our standard of living. In less than 50 years from now, some 400 million Americans are expected to constitute this Nation, more than double the present population. Achieving maximum efficiency from our energy resources is a prime economic goal today, but as our population grows it will become an absolute necessity for maintaining an industrial civilization with a high standard of living for all.

Minimizing energy costs in the years ahead will be a key element in maintaining our predominant position in the world. Our needs for the raw materials to feed our industries will be enormous and we know that while high-grade deposits of many minerals are limited, low-grade deposits are large. The key to transforming many of these low-grade mineral deposits into useful raw materials is low-cost energy. Water supply is already a problem in the West and as water supplies continue to dwindle in relation to expanded requirements, we must expect large electric power requirements for water treatment, desalination and the transportation of water between watersheds. Attaining an abundant low-cost energy base, which the Survey stresses, is among this Nation's most important long-term national concerns.

The Survey findings suggest that no longer need the availability of low-cost power be confined primarily to areas with low-cost hydro power or an economical fuel supply. Low-cost energy transportation is rapidly making all of the Nation's fuel and water power resources a common fund, economically available at great distances from their origin. The dramatic recent improvements in the cost of transportation of fuel by railroad and other modes, and in the transportation of energy itself through EHV transmission lines, will sharply reduce the differences in power costs among the various sections of our country. As power networks cover broader areas power costs should become more uniform and lower. High-rate areas stand to gain the most, first in reductions in power costs and then in an accompanying expansion in the use of electricity and the enjoyment of its benefits.

The Nation is beginning to realize that it has just as great an interest in the full development of our limited number of prime steam plant sites, as in the maximum development of our hydroelectric resources. A good steam plant site requires a location near the fuel source or the market, or both, access to plentiful supplies of condensing water, access to transportation, freedom from flood threat, favorable geological conditions, a large tract of land available at moderate cost, and other site advantages. A site which meets all these criteria should be put to maximum economic use for the benefit of the largest area it can serve.

The industry's pluralistic institutional structure, while perhaps inhibiting coordinated operations, has proven a powerful competitive stimulus to management improvement and cost reduction. The Nation's 3,600 separate electric power enterprises are operated by a great diversity of agencies, some investor-owned, others owned by cities, States, counties, public utility districts and cooperatives, as well as by the Federal Government. Together, they provide this country with a system of power supply which at the retail level is generally responsive to local needs and local control. However, the large number of separate systems coupled with rivalries and controversies between segments of the industry has frequently resulted in economically meaningless boundaries for utility system planning and operation which undoubtedly cost the power consumers of this country millions of dollars every year in wasted opportunities for cost reduction. These boundaries can be transcended without losing the benefits of the existing pluralistic institutional structure if all segments of the industry, and all the individual systems within each segment, would realize that their ideological differences are no bar to working together in establishing stronger regional and interregional power pools. To do so would strengthen all and diminish none.

The National Power Survey does not attempt to resolve or even examine all the existing or anticipated institutional problems of the electric utility industry. Rather, we are here concerned with demonstrating the opportunities of full utilization of our technology and our fuel, capital and management resources, and how they can improve the lives of all Americans in the years ahead.

We are aware that many controversial areas of public policy are related in one way or another to the industry's success in lowering power costs. These policy areas include the territorial integrity of the retail marketing areas of competing systems, the usefulness of public power programs as a yardstick to supplement regulation of privately owned systems, the differential revenue requirements because of variations in the tax, financing and earnings requirements of individual systems, the obligations of the large systems in their relationships with the small in power supply arrangements and in competitive situations, the proper role of statutory preferences to public and cooperative power distributors for the sale of power from Federal systems, and many others. We believe that the National Power Survey Report is not the appropriate medium for attempting to reconcile the conflicting views on these issues of public policy, if that were feasible, or to formulate or express our own views on these issues. The question of the proper scope of government in regulating or conducting economic affairs is one of the root problems in a democracy. We do not attempt to resolve it in this report.

We are convinced that none of these problems present an insuperable barrier to achieving the full benefits of a system of power supply in which the separate and independent ownership of individual systems is preserved, but their facilities are nevertheless coordinated in large power pools interconnected on a nationwide basis to achieve maximum economies. This was also the unanimous view of our Legal Advisory Committee, made up of outstanding lawyers from every segment of the industry. What is required is a good-faith effort by all segments of the industry to coordinate their efforts for mutual benefit. The opportunities afforded by our technology are not the special province of any segment of the industry. Their full utilization can and should be the goal of all segments.

The challenge facing the electric power industry is to continue the long-term trend of selling electricity to the consumer at steadily lower prices. We are suggesting an industry target for 1980 of approximately 1.2 cents per kilowatt-hour as the combined average retail price for all residential, commercial and industrial sales of electricity throughout the Nation. The comparable figure in 1962 was 1.7 cents and in 1940 it was 2.2 cents.

The Commission is aware that it is setting an ambitious goal. There are many items of cost that will undoubtedly increase and net reductions of this magnitude are difficult to attain. However, the electric power industry's performance has always confounded the prophets and exceeded the hopes even of those who believe in the promise of the future. We believe the goal is realistic. A large proportion of the reduction in average price will come from increased usage alone. If we consider, in addition to growth, the many other opportunities for reducing unit costs, who is to say that 1.2-cent power at retail on the average cannot be made available throughout the country by 1980? We believe that if the Nation's number one industry utilizes all of its resources and ingenuity it will meet this challenge. The purpose of the Survey is to suggest the general paths along which this important goal can be achieved.

A guide to an understanding of the industry today and evaluation of its development in the future is the makeup of the so-called "fixed charges." The term "fixed charges" covers the costs which vary with the investment and which are independent of the extent to which that investment is used. Return on investment including bond interest and earnings on the equity capital, depreciation, insurance and property taxes are all items in this category, and the term is also commonly used in the utility industry to cover the income taxes associated with the authorized level of earnings.

For public and cooperative agencies fixed charges are approximately half the level of those of the investor-owned companies. This is due to financing advantages resulting from Federal and state tax exemptions and (in the case of the cooperatives) Federal loans at low interest, and also to the fact that the non-profit nature of the public and cooperative systems makes it possible for them to operate on the basis of a lower earnings level.

The institutional characteristics which result in the fixed charge variations are based upon constitutional and policy considerations which are important and deep-seated and beyond the scope of this report to appraise.

For purposes of most project comparisons the Commission has used fixed charges of about 11 percent, which it determined to be a reasonable weighted average of the combined industry's fixed charges which may be expected for plants built in the next 15 years, thus assuring that projects will be compared on uniform standards. Because hydroelectric generation is often an important part of Federal multipurpose projects to develop a fuller use of our water resources, such projects were also tested on the basis of a fixed charge scale for Federal projects to assure that any meritorious project would not be overlooked. For the purpose of computing the average cost of power in particular regions of the nation on a meaningful basis we used a composite fixed charge based on the fixed charges of the particular power enterprises in the region. These varying fixed charges were not used for any comparisons of projects or project evaluations but merely to provide a realistic basis for estimating power costs in 1980.

A survey of the opportunities for the 1970's must begin with knowledge of the electric power industry as it is serving the Nation today. To fill that need, chapter 1 presents a comprehensive and we believe objective description of the present makeup of the industry with enough of its history to give some insight into the evolution of its special pluralistic structure. The chapter concludes with some interesting statistics on existing rates throughout the country.

The key to the future of the industry is its growth. We are projecting that power demands in 1980 will require the production of 2.8 trillion kilowatt-hours of electricity or more than 2½ times the estimated production of 1.1 trillion kilowatt-hours in 1964. Chapter 2 presents the national and regional demand forecasts which support this projection. The chapter also suggests some of the ways in which electricity can add to the comfort and convenience of the daily lives of everyone.

Chapters 3 through 14 review and project the technology which will be available for building and operating tomorrow's power generating plants and outline complementary or alternative paths of development. Chapter 3 is devoted to fuels and fuel transportation, and chapter 4 to conventional steam plants. Chapter 5 which discusses nuclear plants is of particular interest as it projects a greatly enlarged role for nuclear plants as a source of low-cost power for the decades ahead. Hydroelectric power resources are discussed in chapter 6, peaking power including pumped storage in chapter 7, and the so-called exotic sources in chapter 8.

Chapter 9 of this group is one of general public interest because it deals with environmental considerations such as the means by which pollution of the air and our rivers can be minimized. The chapters which follow, 10–14, outline the developments in extra-high-voltage transmission, both AC and DC, the emerging trends in distribution systems, and the improvements in controls for intersystem operations, developments which are crucial to the broad expansion of our power networks to permit the efficient flow of power from generation source to the ultimate consumer. These chapters also explain the concepts of coordination and the diversities in load patterns and reduction in reserve requirements which full coordination can achieve.

The heart of the Report is chapter 15 which first discusses the criteria for power system planning, and next presents an illustrative pattern of power generation and transmission by 1980, with full regional and countrywide coordination and an indication of the savings that could be achieved as compared with the individual planning decisions of the Nation's power systems. The staff studies support estimates of potential net economies in the order of $11 billion annually from increased usage and from closely integrated power networks covering broad areas of the country, fully recognizing, of course, that the offsetting costs of attaining closer coordination must be accounted for in determining the net savings.

We again emphasize that the depicted patterns are not intended as blueprints. Detailed engineering, which we have not undertaken, must precede any construction, and would undoubtedly point to major departures from the tentative proposals in the Report. What is intended and what we think is shown is the magnitude of the savings and the general outline of a possible approach to the job which can, and we are confident will, be accomplished.

Chapter 15 also suggests, region by region, the general mix of nuclear, hydro, and conventional steam capacity, the general range of desirable unit sizes, and the possibilities for EHV interties. Thus, the Report maps a hypothetical pattern of high-voltage transmission lines and generating capacity for each part of the country. These studies represent the first time that an overall outline for planning the coordinated growth of all of the power systems of this country has been prepared with the view of achieving a common goal of maximum efficiency.

Chapter 16 of the Survey is devoted to the smaller systems which constitute about 3,200 of the approximately 3,600 power systems in the Nation. We have explored the various alternatives by which small systems in every segment of the industry can participate in fully coordinated power networks and thus obtain their power supply from low-cost sources so that they too can share in the benefits of our new technology.

Chapter 17 brings to a focus the economic significance of the patterns of growth we have visualized. It projects the potential savings to consumers which will result from the growth and technological improvements projected in the Survey Report. The chapter suggests the magnitude of these possible savings region by region and projects an overall reduction in the unit cost of electricity of 27 percent by 1980. The reductions are expected to be greatest in New England where existing rates are the highest and to be quite small in the Pacific Northwest which already enjoys the lowest average rates of any region.

The Commission believes that this Survey of the industry in the decades ahead should have a healthy influence on the more immediate management decisions for meeting the loads of the late 1960's and early 1970's. The Report directs attention to the enormous amount of new capacity that will be required, the importance of maximum utilization of our best sites, both hydro and steam, the need for affording small systems a share in the economies of scale, the energetic load-building program that will be required if projected loads are to be achieved or exceeded, and the large savings inherent if individual systems plan and build together rather than separately.

The Report does not consider interconnections and further coordination among systems or existing power pools as a goal in itself. On the contrary, each investment must be justified by economic consideratons, such as direct cost savings, improved service, or greater flexibility and reliability. The potential interconnections we suggest hold promise of meeting this test on the basis of our planning studies but they are intended to be illustrative only and suggestive of further detailed investigations rather than definitive proposals.

The emerging pattern of power supply does not point entirely in the direction of long transmission distance between sources of generation and loads. The competitive pressure of EHV transmission and other new developments in energy transportation, such as the coal slurry pipeline, have stimulated the railroads to introduce improved transportation techniques and to reduce their rates. Such rate reductions improve the economics of plants distant from the coal fields and closer to load because the rates for coal transportation sometimes constitute more than half of the cost of coal delivered to load centers.

A more general use of nuclear plants will also have its influence on transmission line requirements. Fuel transportation costs are not a significant item for nuclear plants, and would not necessarily be higher for plants close to loads than for those located at a distance. On the other hand, the advantages of scale are so pronounced in nuclear stations that large nuclear plants feeding electricity into strongly interconnected grids serving many load centers are likely to constitute an attractive pattern of development in the future.

There are many collateral benefits of a coordinated power supply system with a strong transmission grid integrating the facilities over large areas. Steam generating plants can be located in relatively remote areas with the resulting alleviation of air pollution in metropolitan centers. In the event of extreme air pollution conditions generation in the problem area could be temporarily curtailed and power could be obtained from other sources in the interconnected grid. Strong interconnections are added insurance during many other kinds of emergencies because they make possible transfers of power supply over large areas. This consideration can be of great defense importance because many defense plants such as the aluminum smelters and atomic diffusion plants which are heavy users of power can be fully activated or reactivated on short notice. New industrial plants can be built in a much shorter time than large generating stations which require lead times of 3 to 5 years; power-oriented industries would have greater flexibility in location and in start-up dates with widespread power pooling. The flexibility of strong EHV grids will also permit better utilization of hydroelectric resources so that surplus energy will not be wasted to the sea.

In summary, we look for the construction by 1980 of an EHV transmission system throughout the country which will provide great flexibility for generating station locations.

It is our earnest hope that the National Power Survey, to which many outstanding participants from all segments of the industry have contributed a great deal of supporting information and analysis, will set a standard and be a guide in the future planning of the industry. The goal we propose is an electric power industry animated by a broad and bold vision of its role in contributing to the growth and welfare of the Nation's economy. We have tried to outline a coordinated power system of the future which will meet that test.

CHAPTER I

THE ELECTRIC POWER INDUSTRY TODAY

Electric energy is so basic to our lives that we take it for granted. Yet without electricity there would be no modern communications, no television, no electronics, no electro-process industries, and few of the appliances which have become an indispensable ingredient in the American society of today. This Nation's extremely high use of electrical energy is in large part responsible for our high standard of living and advanced level of industrialization. America, with only 6 percent of the world's population, uses almost 40 percent of the electrical energy produced in the entire world (fig. 1).

The U.S. electric power industry has grown from an infant born in the 1880's to a giant ranked the largest in the nation. It has expanded at a pace nearly twice that of the overall economy, doubling roughly every 10 years and increasing at an annual compound rate of about 7 percent. Electricity provides 20 percent of the basic energy needs in the United States today and is expected to supply 30 percent by 1980.

Total expenditures for electric energy are rising because of the ever-growing consumption of electric power, but the cost per kilowatt-hour is decreasing. The outlook for the future is for still lower rates, with residential and commercial rates leading in the reductions.

A History of Industrial Growth and Cost Reduction

The electric power industry of today, though relatively young, has been built upon the foundation of a long chain of inventions. The water wheel, devised by some unknown innovator many centuries ago, was an early link in the chain. It made available a form of mechanical energy independent of the muscles of man and his domestic animals. A later key development was the recognition of the usefulness of steam to harness the energy in fuels.

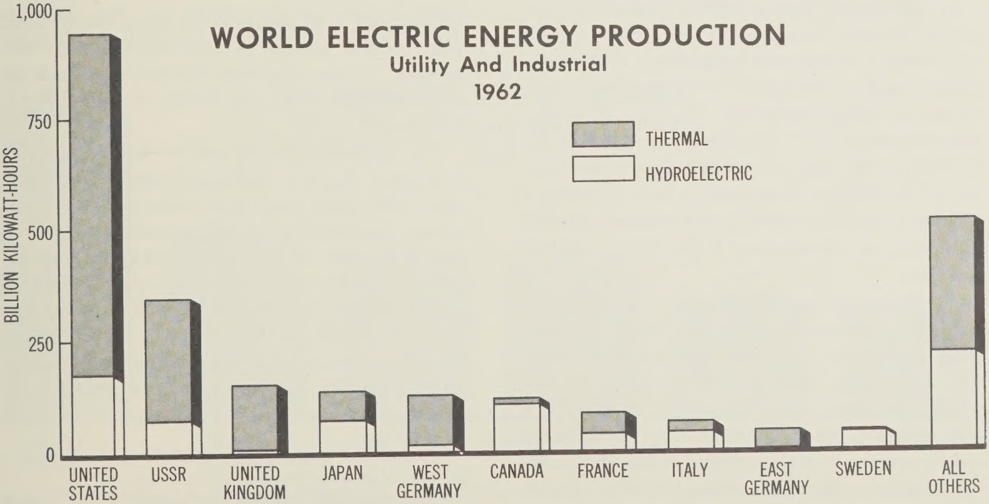
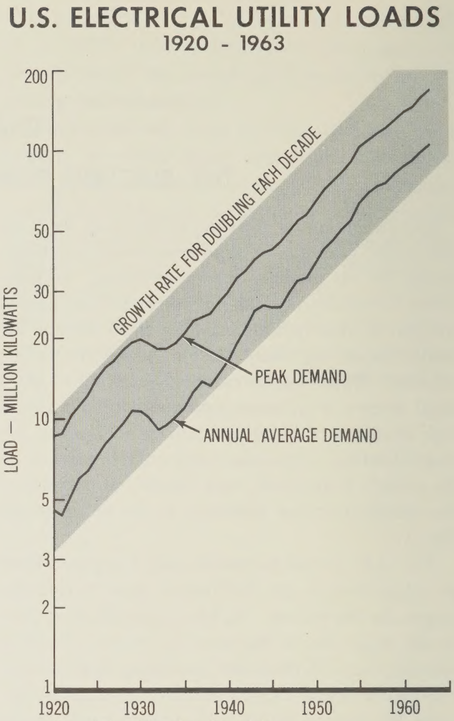


Figure 1

The convenient and abundant use of energy from falling water and fuels became possible only with the development of a technology for converting mechanical energy into electricity. Hydroelectric plants develop the water power potential of our rivers by using the energy of falling water to drive turbines which turn generators that convert the energy to electricity. In steam plants the energy in coal, natural gas, oil and more recently from nuclear particles, heats water to steam. The steam under pressure drives a turbine-generator which converts the energy into electrical form.

The commercial harnessing of water wheels and steam engines to electric dynamos, or generators, and the establishment of electric companies, began late in the nineteenth century. The Rochester (N.Y.) Electric Light Co. founded in February 1880 installed a water-wheel-driven generator for the operation of arc lights; its charge was 75 cents a night for one light and 50 cents each for any others. In September 1882 Thomas A. Edison placed in operation the historic Pearl Street steam-electric plant and the pioneer distribution system by which he supplied electricity for the operation of lamps in the business offices of downtown New York. By the end of that year, the Edison Electric Illuminating Co. of New York was serving 500 customers using more than 10,000 lamps. From this modest beginning has emerged the electric power industry of today.

In the United States, electric power's 80-year growth record is unmatched by any major American industry, in rate and consistency. Production has increased at about twice the rate of increase in overall industrial production (fig. 2). The relative consistency of this expansion, and especially the relatively stable flow of expenditures for new electric power plants and equipment, have provided a persistent impetus to the Nation's economic growth and acted as a cushioning force during business recessions.



Note: Alaska and Hawaii Are Not Included

FIGURE 2

The industry's growth has been spurred by reductions in the cost of electricity relative to other goods and services. Load growth in turn has itself been a factor in inducing cost reduction by permitting the achievement of economies associated with increased use and by providing the industry and its equipment makers with a steady and growing market for improved utility facilities. Figure 4 compares the long-term declining trend in electricity rates with the generally rising prices of consumer goods, as indicated by the cost of living index. This general record of cost reduction is outstanding among American industries. It is an achievement of which the electric power industry is justly proud.

The industry's annual rate of productivity improvement[1] has averaged aproximately 5.5 percent since 1900, more than three times the rate of increased productivity for the economy as a whole. In this respect, electric power ranks first among major American industries in its long-term record and has been among the leaders in nearly every decade.[2] The challenge to the industry in the decades ahead is to continue and improve this record and to insure that the ultimate consumer profits from this improvement.

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[1] Productivity measures an industry's economic output per unit of input in constant dollar terms.

[2] John Kendrick, *Productivity Trends in the United States*, National Bureau of Economic Research, 1961, pp. 136–137.

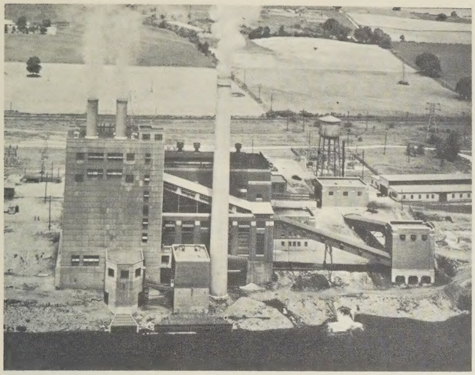
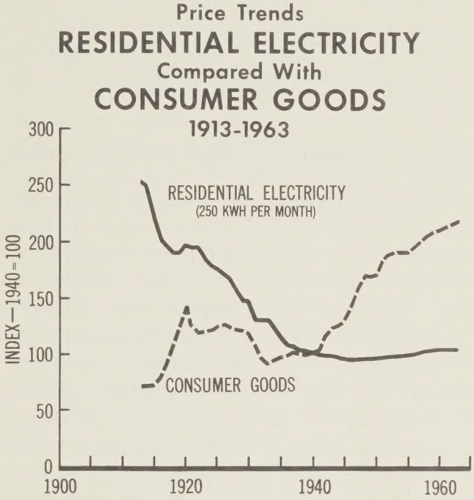


Figure 3 *The Gilbert Plant of the New Jersey Power and Light Co., now over 30 years old, was one of the first U.S. installations to operate at a pressure of 1250 pounds per square inch. The 27% overall thermal efficiency attained by its 57,000 kilowatt, steeple compound unit (No. 1), was the best attainable in the early 1930's.*

Size and Heavy Use of Capital

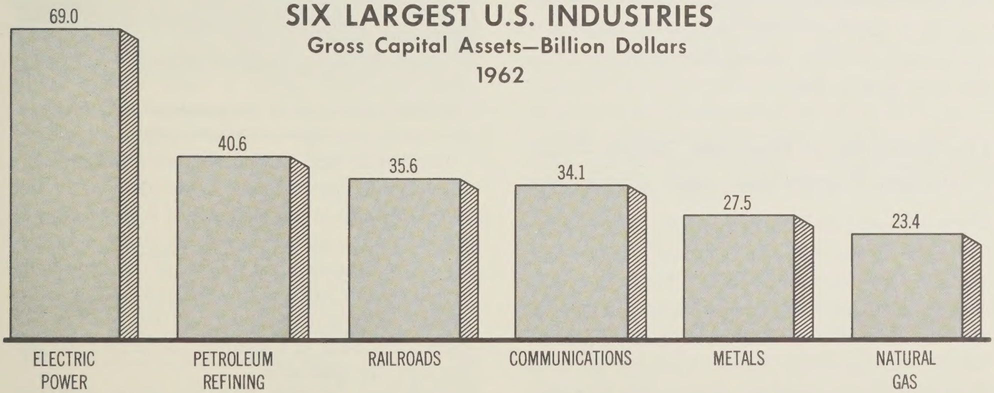
Electric power ranks among the largest industries in the economy, no matter what measure of size is used. It requires extremely heavy use of capital. In terms of the dollar value of plant and equipment the electric power industry is by far the nation's largest. Its annual capital expenditures represent over 10 percent of the total of such spending by all American industries. Its spending on plant and equipment in 1962 alone amounted to $4.3 billion. Its capital assets of $69 billion in 1962 are more than 60 percent greater than its nearest rival (fig. 5).

Largely as a consequence of the industry's heavy capital needs it has become essentially a monopoly. The investment required for power supply is so great that no community can afford a number of competing systems each with the facilities to furnish electric service to the same customer. On the other



Consumer Goods Data Based on U.S. Bureau of Labor Statistics.

Figure 4



Source: Electric Utility Assets—Federal Power Commission Staff; Petroleum and Primary Metals—Internal Revenue Service; Railroads—Interstate Commerce Commission; Gas Utilities—American Gas Association.

Figure 5

hand, electricity competes with other forms of energy for many of its uses and it by no means monopolizes the highly competitive energy market.

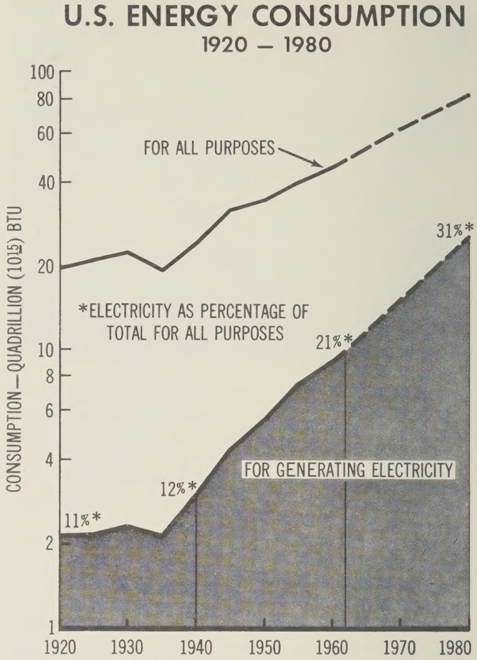
The industry is a leading issuer of securities in the financial markets. Its securities are held by pension funds, insurance companies, charitable trusts and investment funds, as well as by several million individual security holders. These securities represent an investment of over $40 billion in the facilities of the investor-owned segment of the industry and, in addition, many state and local public power agencies, and the Tennessee Valley Authority on the Federal level, obtain funds for their electric power facilities through the securities markets.

Impact of Energy Competition on Growth

The electric power industry is both a major customer for the fossil fuels which provide the heat source for almost all steam-generated electricity and a direct competitor of the fossil fuel industries for many residential and industrial uses. Figure 6 indicates that the electric power industry's share of the Nation's entire basic energy use has grown steadily from approximately 11 percent in 1920 to 20 percent in 1960 and is likely to reach 30 percent or more by 1980. But electricity's share of the energy market will not increase automatically. Future growth will depend increasingly on the outcome of competition with natural gas and oil for space heating and industrial uses. The ability of the electric industry to expand its share of the market in the future will depend on whether it makes the most of its opportunities for reducing the the price of its product.

Characteristics of Electricity Supply—Generation, Transmission and Distribution

There are three distinct functions in supplying electricity to the ultimate consumer: generation, transmission and distribution. These functions correspond to the manufacture, transportation to market, and retail distribution of many products, except that electricity moves from the point of generation to the point of ultimate use in a continuous flow with the speed of light, 186,000 miles per second.



Source: 1920-1960 Based on U. S. Bureau of Census Data and Edison Electric Institute Heat Rates

Figure 6

Generation takes place at hydroelectric plants which transform the energy of falling water into electricity or at steam-electric plants which generate electrical energy with heat derived from the fossil fuels and nuclear fission. Transmission is the transportation of electrical energy at high voltage from generating plants to bulk delivery points. Distribution completes the process of delivery to the individual consumer at lower voltage.

Generation and transmission facilities are as a general rule economically interdependent in that the choice of location, design, and scale of generating capacity must take into account the associated costs of transmission and vice versa. Responsibility for generation and transmission customarily go together. Distribution can be, and frequently is, conducted efficiently as a separate operation from generating and transmission.

A number of basic features of the industry's technology characterize the development of economical power supply.

First, since the industry is one in which capital investment is unusually high, unit costs can be greatly reduced by better utilization of equipment.

Second, unit costs also decline with increased size or capacity of equipment. A single large generating unit can produce power at costs substantially lower than several smaller units having the same total capacity.

Third, production and use must be simultaneous because electricity cannot be stored. Enough capacity is required to meet the coincident demand, or peak load, of all customers. Since the peak loads of individual customers occur at different times, an interconnected network can achieve important economies arising from different time patterns or diversity of use of the component systems in the network.

The combined effect of these factors is that the most economical arrangement for electric service to all customers in a given service area is by a strongly interconnected and coordinated complex of generation and transmission facilities with sole responsibility for meeting all of the power requirements in the area.

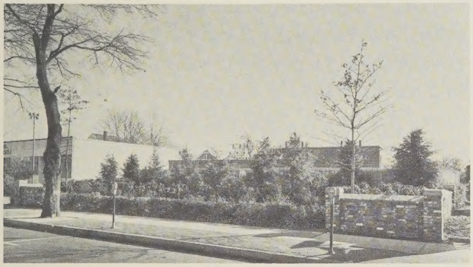


FIGURE 7 *The appearance of the downtown distribution substation of the Long Island Lighting Company is enhanced by attractive fencing and landscaping.*

In the case of distribution, the area economically covered by a single complex can be relatively small. A local community or metropolitan area typically can exhaust most of the economies of size of distribution networks. The real economies in distribution depend upon increasing the use per customer, while the most economical generation and transmission require integration over a large interconnected area.

Growth of Interconnections and Mergers

The Formation of Local Service Areas

The factors requiring unified planning, construction, and operation of generating and transmission networks have been present from the very beginning of the industry, but the size of the area most efficiently covered by a single network has grown as advances in electric technology have increased the economic transmission distance and enlarged the savings from using larger scale equipment.

The first commercial thermal power station, Edison's Pearl Street Station in New York City, included six generators of 120-kilowatt capacity each and served an area of little more than a square mile. Today, a 1,100,000-kilowatt unit—9,000 times as large as one of the first units—is on order, and units of 1,500,000 kilowatts are probable before 1980.

The service areas of the earliest central stations were limited primarily by the very short distance from the point of generation that power could be economically distributed with the low voltage direct current then used. The losses in transmitting the power made service to another city prohibitive and it was not uncommon for a single city to be served by a dozen or more separate systems, each with its own source of generation. The development of the alternating current transformer, first used successfully in 1886, paved the way for a radical enlargement of the area economically served by a single distribution network through the use of higher voltage transmission and distribution lines.

In the early years of the industry, new electric systems were formed at a rapid rate, but as individual electric systems extended their lines to more distant customers, they encountered competition from others. The disadvantages of direct competition were soon discovered, and a wave of consolidations took place. By the turn of the century, the typical situation was one of local monopoly. Regulation, locally by municipal franchise and certificate and on a more comprehensive basis by state utility commissions, expanded rapidly in order to protect the public against wasteful competition and excessive rates and to provide investors with some assurance that their investments would be safeguarded.

Interconnections 1900–1964

The growth in load and advances in technology after 1900 continued to broaden the opportunities for further integration of generation and transmission facilities and utilization of larger scale equipment. However, as tables 1 and 2 indicate, the trends toward larger generating units and higher transmission voltages have been uneven.

TABLE 1

Maximum Sizes of Generating Units in the United States

(In megawatts—1 megawatt equals 1,000 kilowatts or 1,000,000 watts)

	Maximum turbine Rating—MW
1900	1.5
1920	60
1930	[1] 208
1940	[1] 208
1950	[1] 208
1956	260
1958	335
1960	450
1963	650
1965	[2] 1,000

[1] Represents a single unit. More typically, maximum prevailing sizes were 75 mw in 1930, 100 mw in 1940, and 175 mw in 1950.

[2] Under construction.

TABLE 2

Maximum Transmission Voltages in the United States

Year	Kilovolts
1886	3
1892	10
1901	60
1908	110
1923	220
1934	287
1954	345
1964	500

The increase in the size of the largest generating unit in use from 260,000 kilowatts in 1956 to 650,000 kilowatts in 1963 has been spectacular but it was preceded by many decades of relatively slow progress. The current rapid spurt in higher transmission voltage also followed a period of relatively little growth since the 1920's, influenced undoubtedly by the relatively low rate of load growth in the depression of the 1930's, followed by the material shortages in the World War II period.

Interconnections Today

The extent to which electric systems are presently interconnected varies greatly from fully integrated pools in which the capacity of several power systems is planned and built to meet the combined needs of the entire interconnected group to situations in which two systems merely have joined in a low capacity intertie for emergency purposes only.

Today, 97 percent of the industry's generating capacity is to a greater or lesser degree interconnected in five large networks. Each network consists of many systems tied together by interconnections of varying capacity. The largest existing group of interconnected systems involves 167 million kilowatts of electrical generation operating in parallel.[3] It covers roughly the entire portion of the United States east of Texas and the Rockies, as well as much of eastern Canada—39 States and two Canadian provinces in all. It consists of the so-called Interconnected Systems Group, the Pennsylvania-New Jersey-Maryland Interconnection, and the Canada-U.S. Eastern Interconnection. Two other major networks, the Northwest Interconnected Systems Group and the Pacific Southwest Interconnected Systems Group, each represent about 11 percent of total industry load. In addition are the Texas Power Pool and the Rio Grande-New Mexico Pool. (See fig. 8.)

Most of the existing networks were not designed for and are incapable of achieving full coordination, but they represent much technological pioneering and cooperative effort. They are a solid beginning for the stronger interties now being built and planned for the future.

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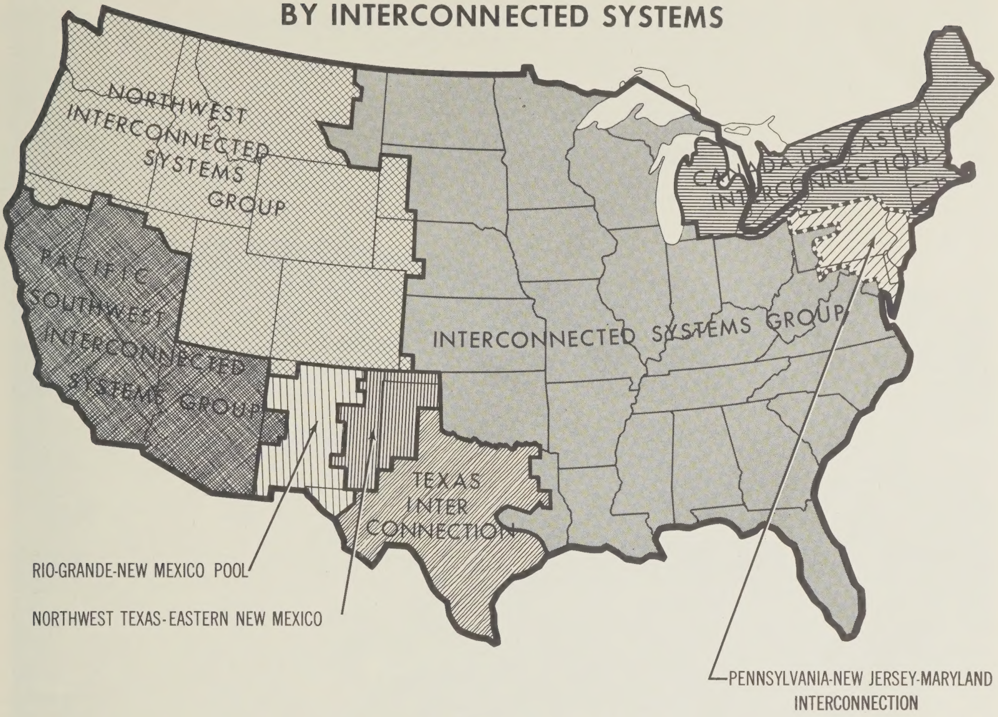
[3] Interconnected Systems Report, 1963. The phrase "operating in parallel" means that the electric power systems in the group are normally operated on a continuously interconnected basis in which some electric energy can flow from one system to the other. The degree of coordination and power flow between systems associated with parallel operation varies greatly with the capacity and location of interconnecting lines and with the extent to which they are used.



MAJOR AREAS SERVED BY INTERCONNECTED SYSTEMS

NORTHWEST INTERCONNECTED SYSTEMS GROUP
PACIFIC SOUTHWEST INTERCONNECTED SYSTEMS GROUP
INTERCONNECTED SYSTEMS GROUP
CANADA-U.S. EASTERN INTERCONNECTION
TEXAS INTER CONNECTION
RIO-GRANDE-NEW MEXICO POOL
NORTHWEST TEXAS-EASTERN NEW MEXICO
PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

Figure 8

Organization of the Power Industry

The industry includes 3,600 systems which vary greatly in size, type of ownership, and range of power supply functions performed. In the diversity and complexity of its organization, the United States electric utility industry is unique among the power industries of the world.

Major Segments

The pluralistic nature of our electric power industry is a natural development in a country which permits its citizens a wide range of choice. The electric power industry is made up of four distinct ownership segments—investor-owned, State and local public agencies, cooperatives, and Federal agencies. Details of the size and composition of each segment are shown on tables 3 and 4.

The largest segment comprises 480 private or investor-owned systems, which own 76 percent of the industry's generating capacity and serve 79 percent of the retail customers.

Second in number of retail customers served is the publicly owned segment which consists of 2,124 State and local public agencies—including municipalities, public utility districts, and State and county entities. This group of public agencies accounts for 10 percent of the generating capacity and serves 13.5 percent of the retail consumers.

Cooperatives, the next largest segment, are a major factor in rural areas. Largely engaged in distribution, they own less than 1 percent of the industry's generating capacity but bring electricity to 7.5 percent of the retail customers.

The Federal segment has 13 percent of the generating capacity. It consists primarily of five large agencies which market the Federally generated power, most of which is produced as part of multipurpose river basin programs. Publicly owned systems and cooperatives are preference customers for Federal power and purchase much of the output

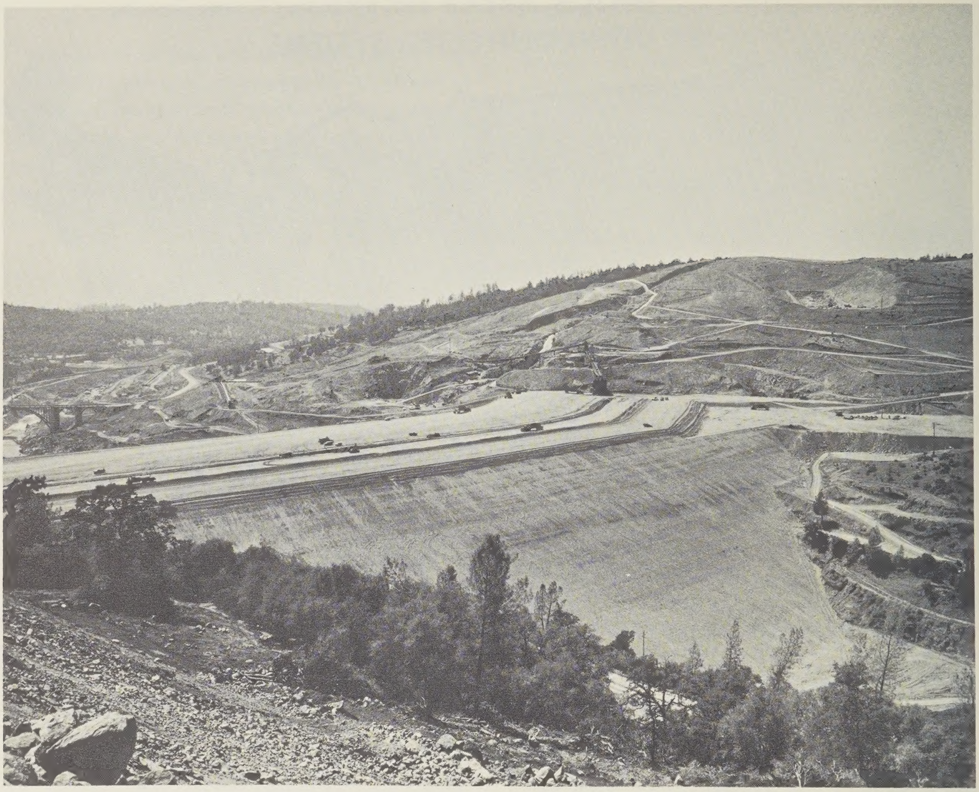


FIGURE 9 *Equipment works on the crest of Oroville Dam as the height of the structure passes 250 feet above foundation, about ⅓ of the final height to be reached in 1968 when this key unit of the California State Water Project is completed. The downstream toe of the dam will extend to the abandoned highway bridge (left).*

of the Federal power plants. However, Federal power is also sold to investor-owned utilities, to industries such as aluminum plants which are large power users, and to Government users. For example, the Atomic Energy Commission in 1963 purchased approximately 40 percent of the entire output of the TVA system.

As shown in table 3, the investor-owned utilities are by far the largest element in the generation of electricity, supplying 76 percent of the Nation's capacity as compared with 13 percent accounted for by the Federal Government. There are over 3,000 non-Federal public and cooperative entities that supply the remaining 11 percent of the generating capacity but who serve 21 percent of the Nation's retail customers. These statistics point up the importance of wholesale power supply to the many public and cooperative distributors. Table 4 shows the large number of small systems in every segment of the industry.

Figure 11 gives the relative share of power production by private and public power since 1930. The change in the public share in this period has been substantial, increasing from 5.5 percent in 1930 to 23.6 percent in 1962. The greater part of this increase has resulted from major Federal undertakings notably the hydroelectric and steam electric generation of TVA and the large scale hydroelectric programs in the Columbia, Missouri, and Colorado River Basins.

TABLE 3

Number of Systems, Generating Capacity, and Customers Served by U.S. Electric Power Industry[1] by Ownership Segment, 1962

Ownership	Number of systems			Generating capacity, percent of total	Retail customers served	
	Total	Engaged in generating and transmission	Engaged in distribution only		Number	Percent
Investor-owned[2]	480	318	162	76	47, 500, 000	79. 0
Public (non-Federal)	2, 124	864	1, 260	10	8, 118, 000	13. 5
Cooperatives	969	76	[3] 893	1	5, 095, 000	7. 5
Federal	44	42	2	13	....	....
Total	3, 617	1, 300	2, 317	100	60, 713, 000	100. 0

[1] Excludes Alaska and Hawaii.

[2] Includes 34 industrial concerns that supply energy to other customers.

[3] Many of the distribution cooperatives are also members of generating and transmission cooperatives (the so-called "G&T's") and hence participate indirectly in the generation and transmission function.

TABLE 4

Composition of the U.S. Power Industry* by Size and Ownership, 1962

Number of systems under separate management or control

Ownership	Annual Energy requirements, billions of kwh				
	Over 10	1.0 to 10	0.1 to 1.0	Under 0.1	Total
Investor-owned	18	88	85	289	480
Public (non-Federal)	0	20	136	1, 968	2, 124
Cooperatives	0	1	64	904	969
Federal Government	2	7	6	29	44
Total number of systems	20	116	291	3, 190	3, 617

*Excludes Alaska and Hawaii.

Size Structure

The 100 largest systems account for about 89 percent of total electric utility generation. Over 2,300 systems are exclusively engaged in distribution, as table 3 indicates. Many others which operate some generating capacity of their own rely on purchased power to meet their growth in requirements. Nevertheless, 900 or more of the systems in the smallest size category shown in table 4, including systems in all ownership segments, own generating capacity of a size limited by their own loads. There are systems in each of the several segments of the industry which operate individual generating units having 100 times the capacity of most of these small plants. The customers of these small systems are not enjoying the benefits of low-cost, large-scale generation.

Geographic Composition

The mixture of types and sizes of electric systems constituting the power industry of the United States varies from State to State and from region to region. In New England the typical electric system is a small- to middle-size investor-owned company. The State of Nebraska is served entirely by systems owned by State and local public agencies.

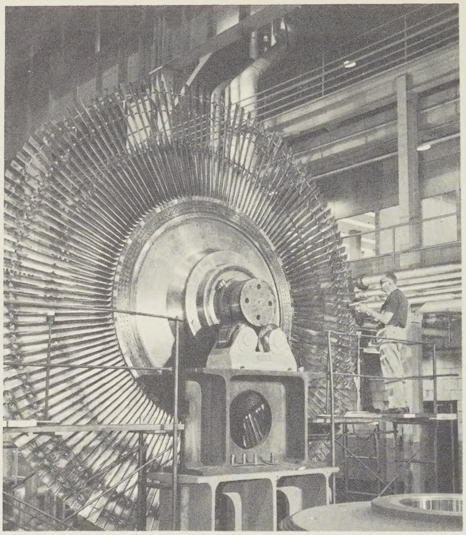


Figure 10 *Special high strength alloy steels, precision machinery, and exacting assembly are essential requisites in the fabrication of a large steam turbine. Here, workman checks assembly of 50-inch buckets on last-stage wheel for 400,000-kw steam turbine-generator.*

Kentucky is one State among many others which illustrates the wide variety of types and sizes of systems. Most customers in the State are served by three major investor-owned utilities. The Tennessee Valley Authority also sells power at wholesale to several municipalities of varying sizes and to several cooperatives. Other cooperatives engage in generating and transmission for sale to distributing cooperatives. A special generating firm, Electric Energy, Inc., located in southern Illinois shares the large Atomic Energy Commission load in Paducah, Ky., with the Tennessee Valley Authority. It is largely debt financed [4] and is owned by participating investor-owned companies.

The Pattern of Service Areas

The complexity of the industry's structure may be seen from figure 12 which shows how the service areas of the major systems in the United States overlap and intertwine. Figure 12 demonstrates the large areas in which costly duplication of facilities would be required if every power system and each segment of the industry plans and builds only for itself. The map thus suggests the great possibilities for reaping benefits if the future load growth in each of these areas can be provided by large-scale generating and transmission networks planned and operated on a unitary basis rather than separately.

Investor-Owned Systems

The present 480 investor-owned systems are largely the result of the merger and consolidation of some 4,000 separate investor-owned systems and some 1,000 additional municipal systems which were once in existence. Approximately 320 of the 480 existing companies are vertically integrated systems, generating most of the power they distribute. These systems account for 70 percent of the total electricity generated by the entire industry, public and private. Most of the approximately 160 remaining investor-owned systems are primarily engaged in distribution.

A major factor in the development of the investor-owned segment was the growth of holding companies after the turn of the century and espe-

TOTAL ELECTRIC ENERGY PRODUCTION BY ELECTRIC UTILITY SYSTEMS

(Excluding Industrial Production)
Billion Kilowatt—Hours

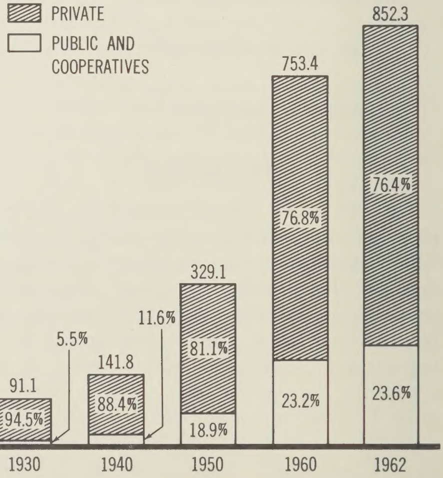


Figure 11

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[4] Interest bearing securities (bonds) as opposed to equities (stocks).

cially in the decade after World War I. The holding company facilitated the integration of ownership and management for contiguous areas previously served by independent systems. Unfortunately, however, holding companies were also used by some for financial empire-building, accounting and financial misrepresentation, and circumventing the intent of regulation. Many of the holding company empires served scattered, noncontiguous territories, and in some cases, competition by holding companies for territory, regardless of location, acted to block power system integration.

By 1929, approximately 60 percent of the industry's electric energy was provided by systems controlled, directly or indirectly, by seven holding companies. The Public Utility Holding Company Act of 1935 provided comprehensive controls administered by the Securities and Exchange Commission to end the abuses of the holding company instrument, including limitation of each holding company to a single interconnected system serving contiguous territory. The SEC has proceeded vigorously under the Holding Company Act to eliminate unnecessary corporate complexity, and has provided continued regulatory control of the remaining holding company systems. Today, sales of energy by the 11 electric holding company systems that remain subject to all provisions of the Holding Company Act represent approximately 21 percent of the sales of electric energy by the investor-owned electric power industry.

The statutes of 46 States provide for public service commissions with varying degrees of statewide jurisdiction over investor-owned electric utilities. These commissions typically regulate rates for retail sales, standards of service, issuance of securities, and accounting. Local regulation—directly and by franchise—is a factor in three of the four States where statewide regulation does not exist, namely Minnesota, South Dakota, and Texas. In Nebraska all electric utilities are publicly owned.

The interstate wholesale rates and services of investor-owned utilities are subject to the jurisdiction of the Federal Power Commission. In addition, utilities making such sales or owning or operating facilities for the interstate transmission of electric energy are subject to the Commission's jurisdiction with respect to their interconnections, mergers, interlocking directorates, accounting, and, in certain instances, issuance of securities.

The investor-owned systems generally serve prescribed areas pursuant to territorial franchises granted by State or local governmental agencies. These franchises are often not exclusive in the technical sense, but under most State laws a second investor-owned company cannot be franchised in a given territory without demonstrating that additional service by the second utility is required by the public convenience and necessity. Territorial competition between investor-owned systems is rare, surviving in only a few cases as a remnant of the industry's formative years.

Competition with systems of different institutional origin is another matter. Competition for loads in suburban areas is common, both between municipal systems and private or cooperative systems serving on the periphery of the cities, and between private systems within the cities and outlying cooperative systems. In most States there are procedures whereby municipalities may acquire existing systems or build their own system.

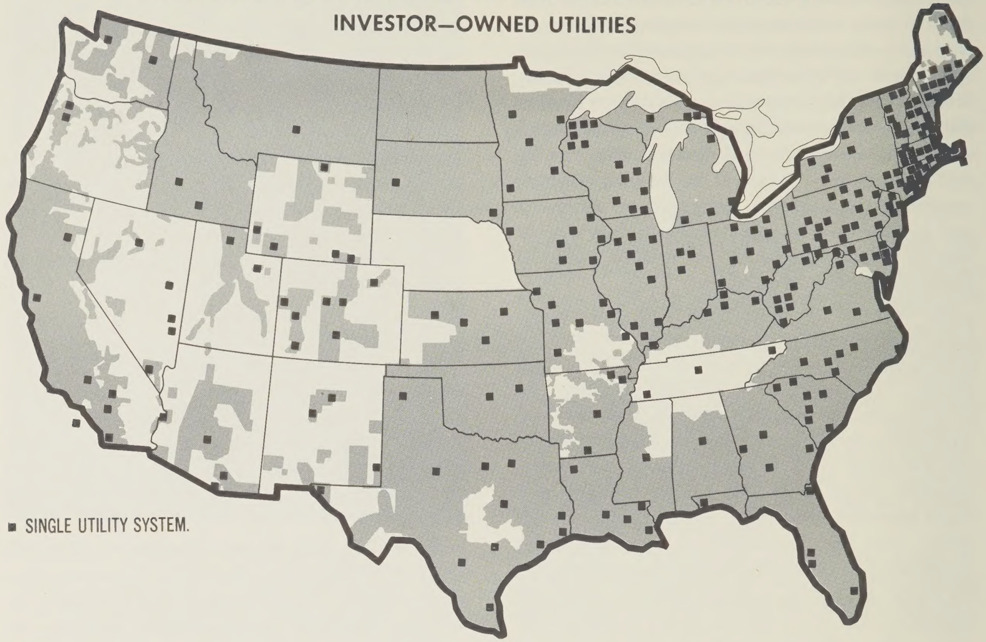
Until 1961, investor-owned utilities obtained the majority of their funds for construction from new security issues. Since the early 1950's, however, internally generated funds—retained earnings, depreciation and amortization, and deferred taxes—have supplied an increasing share. By 1962, nearly 60 percent of the investor-owned segment's construction funds were internally generated, and amortization and depreciation, which supplied 40 percent of construction funds in 1962, has replaced new debt issues as the most important single source of funds.

Table 5 shows the shifts which have taken place in the major sources of construction funds since 1946, a year of very limited construction in which the effects of war-time material shortages on construction programs had not yet been overcome, which explains why over 80 percent of construction needs were supplied from accumulated internal funds in that year. During the postwar boom in construction activity, the source of funds shifted toward security issues. Table 5 indicates that since 1950 there has been a decidedly increasing trend toward a higher ratio of funds from internal financing. The overall capital structure of investor-owned systems consists of approximately 53 percent debt, 10 percent preferred stock, and 37 percent common stock and retained earnings.

Table 6, which traces the composite of the capital structure of the investor-owned segment for

SERVICE AREAS OF ELECTRIC UTILITY INDUSTRY

INVESTOR—OWNED UTILITIES


■ SINGLE UTILITY SYSTEM.

RURAL ELECTRIC COOPERATIVE SYSTEMS

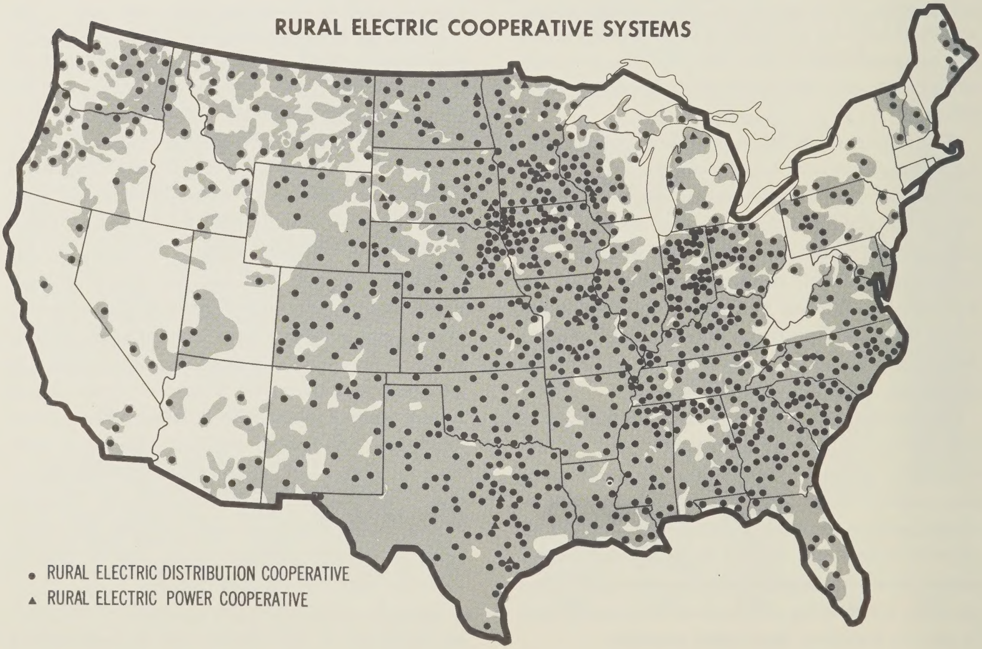
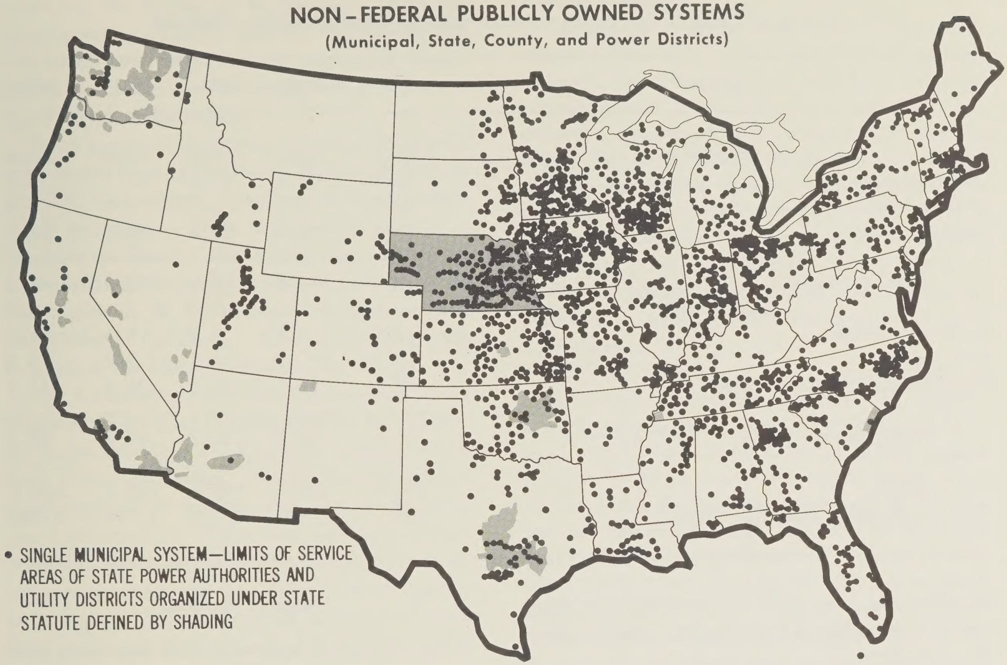

● RURAL ELECTRIC DISTRIBUTION COOPERATIVE
▲ RURAL ELECTRIC POWER COOPERATIVE

Figure 12

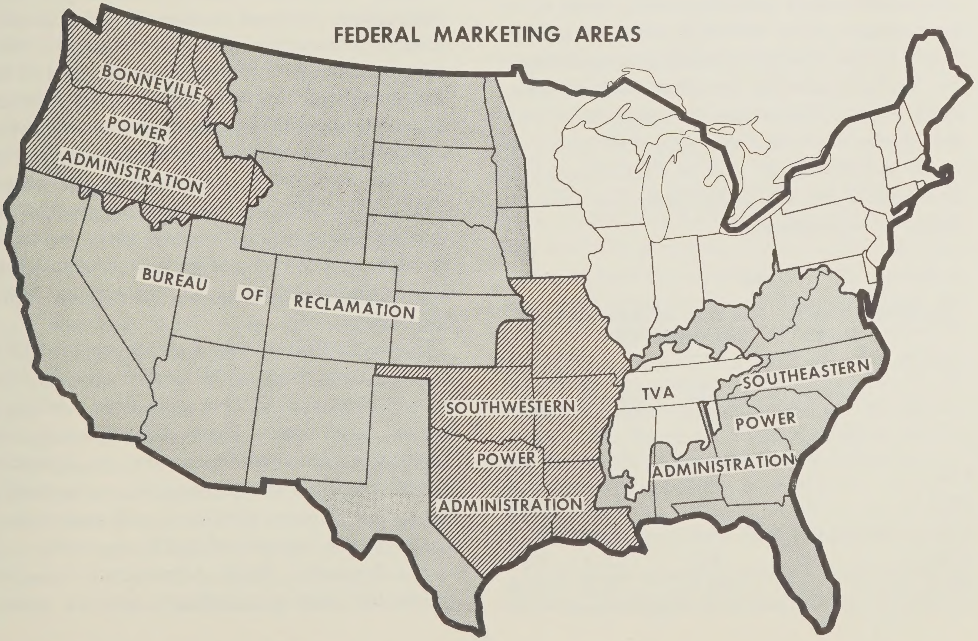
SERVICE AREAS OF ELECTRIC UTILITY INDUSTRY

NON-FEDERAL PUBLICLY OWNED SYSTEMS

(Municipal, State, County, and Power Districts)



• SINGLE MUNICIPAL SYSTEM—LIMITS OF SERVICE AREAS OF STATE POWER AUTHORITIES AND UTILITY DISTRICTS ORGANIZED UNDER STATE STATUTE DEFINED BY SHADING



FEDERAL MARKETING AREAS

BONNEVILLE
POWER
ADMINISTRATION
BUREAU OF RECLAMATION
SOUTHWESTERN
POWER
ADMINISTRATION
TVA
SOUTHEASTERN
POWER
ADMINISTRATION

Figure 12—Continued.

TABLE 5

Sources of Construction Funds Investor-Owned Electric Utilities, 1946–62

Source	1946	1950	1954	1958	1962
Security issues	*Percent*	*Percent*	*Percent*	*Percent*	*Percent*
Common stock	21.4	24.6	17.5	14.5	13.8
Preferred stock	(7.9)	9.5	6.7	6.6	4.4
Debt	5.1	33.0	41.6	38.2	22.7
Total securities	18.6	67.1	65.8	59.3	40.9
Internal funds					
Retained earnings	12.9	7.8	6.2	8.6	14.0
Deferred taxes	......	......	4.5	5.9	3.9
Depreciation and amortization	68.5	25.1	23.5	26.2	41.2
Total internal funds	81.4	32.9	34.2	40.7	59.1
Total	100.0	100.0	100.0	100.0	100.0
Total construction funds ($ millions)	526	1,920	2,950	3,794	3,360

selected years from 1946–62, indicates that there has been little change in the capital structure since the mid-1950's.

Approximately 11 percent of the revenues of investor-owned electric utilities in 1962 were paid in Federal income taxes on the earnings of equity capital. Revenues must also cover State and local taxes, which together approximate the magnitude of Federal income taxes. The aggregate of all taxes paid by the investor-owned sector in 1962, exclusive of provisions for deferred income taxes, was about 22 percent of total revenues.

TABLE 6

Composite Capital Structure Investor-Owned Electric Utilities, 1946–62

Year	Common stock	Earned surplus	Preferred stock	Debt
	Percent	*Percent*	*Percent*	*Percent*
1946	32.1	6.3	15.2	46.4
1950	29.8	7.1	13.6	49.5
1954	28.7	7.7	12.4	51.2
1958	26.7	8.5	11.3	53.5
1962	26.8	10.2	10.2	52.8

Federal Systems

The Federal Government is an important contributor to the Nation's electric power supply. Federal power is produced at approximately 125 projects which are part of Federal multipurpose water resource developments, and at steam plants of the Tennessee Valley Authority (TVA), The agencies primarily responsible for the construction, operation and maintenance of Federal projects are the Bureau of Reclamation, the Army Corps of Engineers, and TVA. In addition, several small projects that include electric power facilities have been constructed by the Bureau of Indian Affairs, the National Park Service, and the International Boundary and Water Commission.

Nearly all Federal power is marketed by TVA and four Department of the Interior agencies—Bureau of Reclamation, Bonneville Power Administration, Southwestern Power Administration, and Southeastern Power Administration. As of January 1, 1964, the Interior Department was the marketing agency for the power developed at 95 projects having an installed capacity of 13,900 megawatts.

The Bonneville Power Administration markets power generated at hydroelectric projects, located in the Pacific Northwest, of both the Corps of Engineers and the Bureau of Reclamation. BPA has constructed an extensive regional transmission system which provides for a large measure of coordination of the total power supply, both Federal and non-Federal, in that region.

Power generated at Bureau of Reclamation projects, except those in the Pacific Northwest, is marketed by that agency. Also, the Bureau markets power generated at Corps of Engineers' projects in the Missouri Basin. The Bureau has constructed transmission facilities to interconnect plants in the Missouri Basin, the Pacific Southwest, and the Central Valley of California. It is constructing such facilities in the Upper Colorado River Basin.

The Southwestern and the Southeastern Power Administrations have the responsibility for marketing power from Corps of Engineers' projects within their respective regions. SWPA has constructed some transmission facilities and is planning additional construction. SEPA does not operate transmission facilities but markets power through wheeling arrangements with non-Federal utility systems in its region. Power generated at Corps of Engineers' projects in the Cumberland River Basin is sold by SEPA to TVA.

Power rates established by BPA, SWPA and SEPA are subject to confirmation and approval by the Federal Power Commission. Rates for power sold by TVA are not subject to such approval and, except for a few specified projects of the Bureau of Reclamation, power marketed by that agency also is not subject to FPC approval.

TVA, which serves 80,000 square miles in the Tennessee River Basin area, is the only Federal agency with full responsibility for meeting all power supply requirements in any sizable area of operation. With over 13,000 megawatts of generating capacity, 9,300 of which is in steam electric plants, the Tennessee Valley Authority is the country's largest electric system, with approximately twice the capacity of the next largest.

The remaining Federal systems are exclusively hydroelectric and supplement the supplies of other systems in the areas in which they operate. Federal agencies sell at wholesale for resale to public and cooperative preference customers, to investor-owned utilities, to Federal installations (such as atomic energy plants) and in some instances to large industrial customers.

The Federal Government sells power to approximately 1,050 electric utility systems in all sections except in the northeastern and portions of the north-central United States. Public agencies and cooperative systems are given a statutory preference to buy the output of all Federal projects. Consequently, the Federal system will occasionally displace an investor-owned system as the supplier to a preference customer. Furthermore, the availability of Federal power at wholesale may encourage a preference agency to acquire its own distribution system in an area previously served by an investor-owned system.

With the exception of TVA, capital funds for Federal systems are supplied entirely by congressional appropriations. Since 1959, TVA has been empowered to obtain funds in the private capital markets by the issuance of revenue bonds. The Government's appropriation investment in TVA, as well as retained earnings, are treated as equity junior to the revenue bonds sold to the public. Since the 1959 self-financing Act, TVA is required to pay the U.S. Treasury a "return" or "dividend" on the appropriation investment equivalent to the average rate of interest paid by the United States on its outstanding marketable debt. TVA is also required to repay $1 billion of the appropriated investment of $1.2 billion within the next 59 years.

Federal systems are not subject to Federal and State income taxes or to local property taxes. TVA, however, makes substantial payments in lieu of taxes to State and county governmental units.

There is not complete uniformity in the repayment requirements for Federal projects or in earnings standards for power sold from these projects. Normally, payments are required for the equivalent of an interest assessment and for amortization of the project investment allocated to power. Interest on new projects is currently computed at 3⅛ percent per annum, the average of the interest rate on all outstanding long-term securities of the United States. This figure has gradually risen as the interest rate paid by the Government on new issues—now over 4 percent—has increased.

State and Local Public Agencies

Local public agency ownership began early in the industry's development, when numerous municipal systems were organized to provide electricity to previously unserved areas. There were more than 700 public systems in 1900 and over 3,000 by the early 1920's, compared with approximately 2,100 today.

The public systems are well described in the report of the Legal Advisory Committee as follows:

> * * * there are many types of public agencies that maintain their own electric generation, transmission, or distribution facilities, or combinations thereof. These include towns and cities of greatly varying sizes, ranging from the smallest to the city of Los Angeles, whose Department of Water and Power serves over a million customers in the city with power generated at Hoover Dam some 250 miles distant, as well as by the Department's own hydro and steam plants, soon to be supplemented by a proposed atomic energy plant. Although, it is not a common occurrence, a small number of counties such as Crisp County, Ga., and three counties in the TVA area, maintain their own systems. However, the most common forms of public entities, other than municipalities, providing electric service are special utility districts (exemplified by the numerous public utility districts of Nebraska, Oregon, and Washington), municipal utility districts (such as the Sacramento Municipal Utility District in California), irrigation districts (some of which, such as the Imperial Irrigation District in California, also maintain electric utility systems) and the various kinds of State "authorities" (such as the Grand River Dam Authority in Oklahoma, the Colorado River Commission of Nevada, the Power Authority of the State of New York and the Arizona Power Authority).[5]

The statutory and constitutional framework within which these public entities were created has tended to maintain their separate identities, and there is great diversity in the nature of their operations. Many municipalities and other local public agencies generate their own power requirements in varying degree, while others purchase power from Federal, investor-owned, cooperative, or other local public systems, and sometimes from a combination of such suppliers. A few are largely confined to the generating and transmission functions. An example is the Power Authority of the State of New York, which sells at wholesale the power it generates at its two big hydroelectric projects at Niagara Falls and the St. Lawrence Seaway.

The great bulk of the local public agency systems are municipally owned and serve only the areas of the municipalities themselves. In a relatively few instances (*e.g.*, Cleveland, Ohio), a municipal system and an investor-owned system serve within the same municipality. However, territorial competition between municipal systems and others is usually confined to the expansion of municipal boundaries, which may bring competition to fringe areas previously served by cooperatives or investor-owned systems.

In 10 States[6] municipal systems are fully regulated by the State's public service commission. In eight additional States[7] some or all such systems are subject to varying degrees of regulation by a State regulatory agency. In the remaining States, they are not regulated by State commissions, but are subject to State laws and are governed by boards of public officials directly or indirectly responsible to the electorate.

Normally, rates and rules for service by municipalities are established only after public hearings. Some local public agencies are subject to a degree of Federal regulation as hydro project licensees under the Federal Power Act or as purchasers of power from Federal systems which impose resale rate requirements on their customers. For instance, TVA maintains strict control of the resale rates of its distributors, and the Bonneville Power Administration imposes a degree of resale rate control.

The local public agency systems generally obtain their capital investment funds from power revenues and by selling debt securities in the public market. In the past, such securities were often general credit obligations of the municipality, county or State. More recently, however, the emphasis has been on revenue bonds issued by the utility system itself, pay-

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[5] Advisory Committee Report No. 22, p. 378 of Part II.

[6] Indiana, Maine, Maryland, Montana, New York, Rhode Island, Vermont, West Virginia, Wisconsin, and Wyoming.

[7] Colorado, Kentucky, Louisiana, Massachusetts, Nebraska, Nevada, New Jersey, and Pennsylvania.

THE PIONEERS

FIGURE 13 *The powerhouse galleries of the Rocky Reach Dam on the Columbia River in Washington, contain attractive displays of Indian and pioneer artifacts, weapons, clothing and occupational products. Other galleries have atomic age displays and art work and creative attractions which are changed periodically. The dam was completed by the Public Utility District No. 1 of Chelan County in 1963.*

able from revenues alone and not backed by the general credit of the local government or by a lien on physical properties.

Local public agencies are traditionally exempt from Federal income tax and generally not subject to State income tax. In most jurisdictions, they are also not subject to real property or other local taxes. However, by statute or ordinance in some jurisdictions and by agreement or practice in others, most local public agencies make substantial payments in lieu of taxes to their own local governments and often make large additional contributions to such governments. Many of them also make payments in lieu of tax payments to State and county governments. In addition, many municipal systems provide power free or at reduced rates to the city government for street lighting, water pumping, and other municipal uses.

Interest on the debt securities of such local agencies is exempt from Federal income tax and, in most jurisdictions, from State income tax, so that their debt securities command more favorable terms than debt securities issued by comparable investor-owned electric utility systems.

Rural Electric Cooperative Systems

The electric cooperative became a significant part of the electric industry beginning in the middle 1930's. Prior to that time, the investor-owned segment of the industry had extended electric service to only about 10 percent of the farms of the country, because it was generally believed that rural service would not yield an adequate return on the required investment.

The Rural Electrification Act of 1936 was designed to stimulate farm electrification through low cost loans by the Rural Electrification Administration, of the U.S. Department of Agriculture, originally established in 1935 by executive order of President Roosevelt. The REA program has been extremely successful. Today, as a result of the REA program, and the expansion of the investor-owned companies' rural electrification programs, 98 percent of the Nation's farms are electrified. There are now almost 1,000 cooperatives participating in the REA program, serving 50 percent of the consumers in the Nation's rural areas. Although REA may make loans to investor-owned and public systems, the cooperatives have come to be the preferred vehicle for the extension of rural electrification with Federal funds.

The vast majority of cooperatives are merely distributors and purchase all of their power at wholesale from the Federal power marketing agencies or investor-owned utilities. However, some groups of distribution cooperatives have formed generating and transmission cooperatives to generate a part or all of their electric power requirements. The "G & T" cooperatives now supply about 15 percent of the requirements of the cooperative segment. These "G & T" cooperatives are also financed by REA with only one recent exception.[8]

The Rural Electrification program initially limited its loans to cooperatives to serve communities of not more than 1,500 persons which were without central station service. With the population shifts of the last three decades, it is not surprising that some cooperatives now serve sizable communities. However, the cooperative systems typically serve areas of low customer density which, of course, increases the cost of distribution. Cooperatives average about 3 customers per mile of line compared with 20 customers per mile for the industry as a whole.

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[8] Buckeye Power Inc. in Ohio.

Except in a few States, the cooperative systems are not granted exclusive franchises for their service areas, and there is much competition between them and other systems for service to new loads. The annexation by municipalities of suburban areas initially served by cooperatives is a major cause of territorial competition. In some areas competition has led to the construction of duplicate facilities. In other areas, there are formal or informal arrangements which permit both systems to minimize the cost of service to their respective customers.

Only a small portion of the capital requirements of cooperative systems is obtained from their membership. The remainder of the capital needed for expansion of the cooperative systems is provided largely by long-term mortgage loans from the Rural Electrification Administration. Interest on such loans is authorized by law at 2 percent per annum.

Rates for service of cooperative systems are designed to cover costs and amortization requirements of REA loans and to provide for contingencies. Payments by consumers in excess of the cost of supplying electric energy are deemed to be capital. This capital is commonly credited to each consumer on a patronage basis and is retired on a revolving basis when the financial condition of the cooperative permits. Most cooperative systems do not return all such capital, at least until a desired reserve level has been accumulated.

Under present law the courts have held the cooperatives not to be liable for Federal and State income taxes. Most cooperatives do, however, pay varying amounts of state and local taxes.

The foregoing factors all tend to minimize the revenue required by cooperative systems to cover the fixed charges for the servicing of investment, thus permitting service to areas of low density which could not otherwise be served at all, or at lower rates than would otherwise be possible.

Rural cooperative distribution systems are subject to varying degrees of regulation by State commissions in 30 of the 46 States in which they operate.[9] In 22 of these States the statutes authorize their respective State public utilities commissions to exercise rate regulation in some form with respect to cooperatives.[10] Loan contracts with the REA provide a contractual basis for controls by the Rural Electrification Administrator over certain aspects of the borrowers' operations. Cooperatives are also subject to corporate control by the member-consumers. The status with respect to Federal Power Commission regulation of those cooperatives which are engaged in the transmission of power in interstate commerce or who sell power at wholesale in interstate commerce is the subject of a proceeding now pending before the FPC. However, the Commission has deferred further action in the proceeding until after January 1, 1966.

Components of Electric Power Supply

A power supply system is composed of many interdependent parts but they can be divided into three distinct functions—generation, transmission, and distribution. The relative cost of each of these functions based on a composite national average for all segments of the industry is shown in table 7.

TABLE 7

Total Delivered Cost of Power—1962
Composition in percent

	Fixed charges	Operating expenses	Total cost
Generation	28. 2	22. 8	51. 0
Transmission	7. 9	2. 0	9. 9
Distribution	22. 8	16. 3	39. 1
Total	58. 9	41. 1	100. 0

There may be substantial deviations from these averages for individual systems, of course. Transmission costs, for instance, are less than 4 percent of total cost in New York City but almost 20 percent in the low density areas of northern Minnesota.

Generation

Generating plants fall into three principal types: steamplants, hydroelectric stations, or pumped storage projects. Although diesel engine and gas turbine driven generators are numerous, they are small in size and account for less than 1 percent of total installed capacity.

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[9] Alabama, Alaska, Arizona, Arkansas, California, Colorado, Delaware, Idaho, Indiana, Iowa, Kansas, Kentucky, Maine, Maryland, Michigan, Mississippi, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, Oklahoma, Oregon, Rhode Island, South Carolina, Vermont, Virginia, West Virginia, Wisconsin, Wyoming.

[10] Alaska, Arizona, California, Colorado, Delaware, Indiana, Kansas, Kentucky, Maryland, Michigan, Mississippi, Nevada, New Hampshire, New Jersey, New Mexico, Oregon, Rhode Island, South Carolina, Vermont, Virginia, West Virginia, Wyoming.

Steamplants generate electricity from the energy in fossil fuels or nuclear sources which heats water to steam. The steam under pressure drives a turbine, which converts the energy into electrical form.

Hydroelectric plants develop the water power potential of our rivers by using the energy of falling water to drive the turbine.

Pumped storage has received added attention over the last few years. It utilizes inexpensive steam-power, generated during the offpeak hours of the day, to pump a relatively small amount of water to a pool at a much higher elevation where the water is stored until the time of the peak loads when it is released to generate hydroelectricity.

As indicated by table 8 steamplants utilizing the energy of coal, natural gas, or oil account for 81 percent of the electricity produced by the industry today. Details of the huge fuel requirements needed to operate these plants and the importance of fuel and fuel transportation in the total price of electricity are presented in chapter 3.

Despite the large development of the Nation's hydroelectric potential in the past three decades, the percentage of the Nation's electric energy supplied by hydro generation has been declining. Table 8 shows the trend, which is expected to continue because good hydro sites are not unlimited. The picture however is not uniform throughout the country. Hydroelectric power still constitutes 93 percent of the capacity in the Pacific Northwest but only 30 percent of the capacity in the Tennessee Valley. In the region of the eastern coal fields (FPC Statistical Region II), hydro power is only about 1 percent of the total. The variation in the proportions of hydro power from area to area is illustrated by figure 14. Chapter 6 presents a full picture of the present and future role of hydro power.

Technological pioneering in increasing the size of steam powerplants and improving their efficiency have steadily reduced the amount of fuel required to generate a kilowatt-hour of electricity in conventional steam-electric plants, as figure 15 illustrates. The prospects for further improvement are discussed in chapter 4.

Transmission

The strategic importance of transmission is much greater than is indicated by its 10 percent average share in the overall cost of electricity. Adequate interconnections where economically justified provide the key to large-scale, low-cost generating units, to major savings in capacity due to load diversity, to the sharing of reserve generating capacity, and to the most efficient utilization of existing generating capacity. In short, interconnection is the coordinating medium that makes possible the most efficient use of facilities in any area or region.

Recent developments in transmission technology, discussed in chapter 10, have greatly reduced the cost of moving large blocks of power. The development of extra-high-voltage transmission now permits the movement of large amounts of power over relatively long distances without the high transmission losses associated with lower voltages. The capital cost of high capacity lines is also being reduced as a result of technological improvements. Although almost all transmission in the United States at present is by alternating current (AC), with a continuation of recent research efforts and technological progress, direct current (DC) transmission may also become an important factor in long distance point-to-point transmission where numerous taps and interconnections are not required.

Transmission voltages presently in use range from 69 kilovolts to 345 kilovolts, and several lines to be operated at 500 kilovolts are under construction.

TABLE 8

Sources of Electric Utility Generation
Percentages of Total Kwh, 1930–63

	1930	1940	1950	1960	1963
Coal	56	54	47	54	54
Natural gas	7	8	14	21	21
Oil	3	4	10	6	6
Water power	34	34	29	19	19
Nuclear	0	0	0	0	0. 1
	100	100	100	100	100

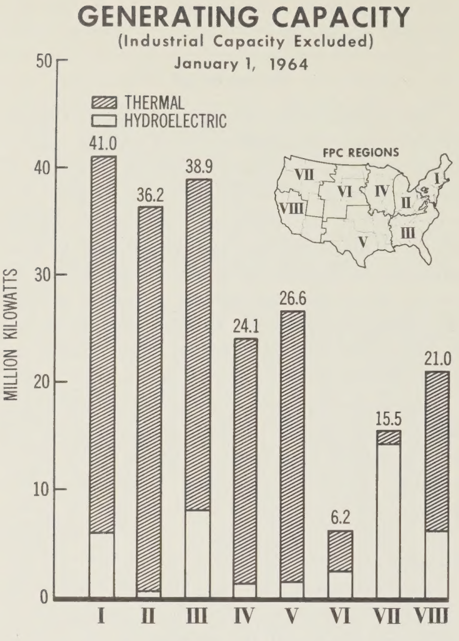

GENERATING CAPACITY
(Industrial Capacity Excluded)
January 1, 1964

Figure 14

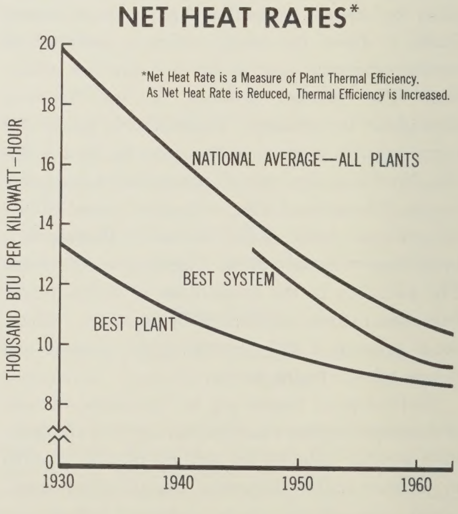
In terms of mileage, about 25 percent of all transmission lines in the country today are 44 kilovolts or below; about 60 percent are 69 kilovolts or below; about 77 percent are 115 kilovolts or below; and over 90 percent are 161 kilovolts or below. Perhaps 5 percent of all power generated in the country, or about 44 billion kilowatt-hours annually, is lost in transmission.

The existing transmission line pattern reflects the fact that most electricity is now generated in plants located close to the load centers. This pattern is being changed in some instances as the improving transmission technology at voltages of 345 kilovolts and above increases the economic attractiveness of large plants serving many load centers and located near the coal fields or other fuel sources. The advancing trends in transmission are discussed in chapter 10 and are portrayed in chapter 15.

Distribution

Distribution costs comprise about 40 percent of the total cost of electricity to residential and commercial consumers. They are relatively insignificant in serving large industrial loads. Distribution is commonly considered to include all of the facilities needed to deliver power from the utility's primary transmission network to the door of the customer. This includes the subtransmission lines with voltages of 11 kilovolts to as high as 161 kilovolts, the primary lines which feed the power from outlying substations into major distribution areas at voltages of 2.3 kilovolts to 34.5 kilovolts and then the secondary distribution lines which we see along the city streets that bring the service directly to the individual customers. The cost of distribution includes the cost of operating the distribution system and the very substantial cost associated with servicing individual customers including meter reading, billing and collections. This latter group of activities accounts for a principal part of the employees and costs associated with central office and suboffice operations.

The physical nature of distribution systems permits many small distributors to operate their systems with a quality of service and at costs which are frequently comparable to those of larger power systems. A major reason why relatively small distribution systems are economically feasible is that the cost of distribution is much more sensitive to the intensity of customer loads than it is to the size of the system. The advantages of scale have limited application to the inherently small scale nature of the distribution function. There are, of course, many advantages of larger systems in more efficient purchasing, emergency service, more funds avail-


NET HEAT RATES*

*Net Heat Rate is a Measure of Plant Thermal Efficiency. As Net Heat Rate is Reduced, Thermal Efficiency is Increased.

Figure 15

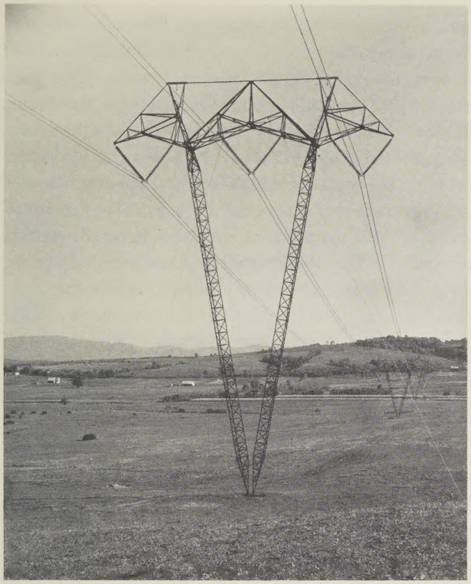


FIGURE 16 *The first transmission of power in the United States at a voltage of 500 kilovolts was initiated late in 1964 by the Virginia Electric and Power Co. to bring power from its new mine-mouth plant in West Virginia to major eastern load centers. The line will become a part of a major 500 kilovolt interconnecting network extending from the Carolinas to New England. Total height of tower is in excess of 90 feet.*

able for research and development, and other considerations. However, the basic tool for reducing the unit cost of distribution is increasing the use of electricity by each individual customer and this tool is available equally to small distributors and the large ones, as has been amply demonstrated by small distributors in various areas of the country.

Much of the physical facilities of a distribution system and the cost of maintaining a distribution business are also related to the number of customers per mile of line. The savings of increased density, however, reach a point of diminishing returns in major metropolitan centers where the cost of the necessary underground installations may be very large.

Distribution systems in the congested areas of large cities are invariably placed underground and in a good many cities underground service extends beyond the congested fringe into apartment and commercial sectors. Until the last decade, practically all outlying residential areas were served by overhead distribution lines. This practice is gradually changing and many of the new residential sections are being served by underground distribution facilities. Recent developments and improvements in construction practices have greatly reduced the extra cost of underground placement. A more detailed discussion of distribution practices and opportunities is contained in chapter 10.

Intersystem Coordination

Interconnection and coordination in various forms began early in the history of the industry and experienced significant growth during the 1920's. The Connecticut Valley Power Exchange, formed in 1925, pioneered in applying the techniques of efficient operation on a multisystem basis. The Pennsylvania-New Jersey Interconnection, which began the following year involved construction of a jointly planned transmission loop. At almost the same time, several mid-western utilities, the nucleus of the present-day Interconnected Systems Group, were tackling the technical problems of control, a solution to which was necessary if reliable parallel operation of large multisystem networks was to become a practical reality.

Coordination of generating capacity additions of several systems to meet their joint needs began early but on a limited scale. Contracts by which one system would sell the temporary surplus capacity of a new generating unit to another system were in existence during the 1920's, and several jointly owned generating plants were built in that period.

The subsequent development of coordination has featured extension and refinement of the techniques and principles applied on a limited scale during the 1920's. Coordination was stimulated by World War II, when it was necessary to pool the existing capacity of many systems in order to meet wartime emergency demands without curtailing service. The circumstances of the postwar period with rapidly increasing loads, major increases in unit sizes, and improvements in transmission technology, have led to increased coordination in most areas of the country. A major goal of the Survey is to encourage all power systems to accelerate their coordination efforts.

Coordination Today

Most of the major systems coordinate bilaterally through individual arrangements with neighbors, usually contractual but in some cases through unwritten working agreements. A growing number of systems also coordinate on a group or multilateral basis through "power pools" (coordinating groups), which vary greatly in the range of functions they perform, the degree of formality and complexity of their organization and the effectiveness of their coordination. In many cases, if not most, a single system may belong to more than one such group and perhaps may have additional coordinating relationships with others inside and outside the group.

It is customary for existing arrangements to provide for a sharing between systems of the benefits of interconnection and coordination. The arrangements customarily involve the sharing of reserves, the alternation of generating capacity additions in order to gain the mutual advantage of larger units than would otherwise be possible, and often the pricing of both firm and surplus power transactions so as to divide the benefits more or less equally between the parties.

The intricacy of existing coordination arrangements may be seen from a few examples. The Hartford Electric Light Co., a medium-sized New England utility with a preference for coordination on a highly organized, formal basis, engages in comprehensive joint system planning and coordination of capacity additions with its two major Connecticut neighbors through the Connecticut Capacity Coordinating Plan. While fully integrating with its immediate neighbors, its operating functions are also coordinated through a larger group, Connecticut Valley Electric Exchange (CONVEX), which includes the Connecticut firms plus an additional neighbor in Massachusetts. In turn, all of the major systems in New England, including the Hartford Electric Light Co., are represented in a New England-wide informal coordinating organization which facilitates some phases of operating coordination. Most of these systems, including Hartford, are also joint owners of two separate corporations—Yankee Atomic and Connecticut Yankee—which were formed to build and operate major nuclear power generating plants. In addition to its heavy involvement in multilateral coordination, Hartford Electric coordinates bilaterally, by contract and informally, with other systems in Connecticut and Massachusetts.

A somewhat different, but no less complex, pattern of organization characterizes the American Electric Power Co., the country's largest investor-owned company in terms of generating capacity, which (through six operating subsidiaries) serves a long, irregular area extending in a southeasterly arc from the outskirts of Chicago to southwestern Virginia. The AEP conducts most coordinating functions bilaterally with major neighboring systems, by means of over 200 interconnections. This coordination is implemented principally by contract, supplemented by working arrangements of a less formal nature and by some major ventures involving joint ownership, including the Ohio Valley Electric Corp., a large generating firm created primarily to serve a major Atomic Energy Commission installation.

An outstanding example of the coordinated operation of the facilities of a group of power systems is found in the Pacific Northwest, where the generation is primarily hydroelectric. Twelve systems, private, public, non-Federal, and Federal, attain a high degree of coordinated operation of their hydroelectric facilities under terms of the Pacific Northwest Coordination Agreement. The Agreement is a complex one but its basic purpose is simple—to provide for operation of all the power facilities of the region with maximum efficiency and to make provision for an equitable sharing of the benefits of coordination.

Existing Rates

The ordinary American citizen's main contact with the electric power industry is the receipt of his electric bill each month. The electric bill represents a regular expenditure which must be covered in the budget of over 50 million American families. Reliable electric service is taken for granted, but consumers are vitally concerned with the rates they must pay to obtain this service. For those in the very lowest income groups it may represent one of the larger items of cash outlay.

The consumers' electric bill represents a growing expenditure because of increasing usage despite the resulting lower cost per kilowatt-hour. Thus from 1951 to 1961, a period when the level of electric rates increased slightly there was, nevertheless a decline of about 13 percent in the average cost per kilowatt-hour of residential electricity. The reason was the effect of lower rate blocks on the growing per capita usage during the decade. The doubling of the average usage per residential customer during the period did not double the cost but resulted in a net increase in the average consumer's monthly bills of about 70 percent.

Our projections indicate that per capita use of electricity will continue to increase and expenditures for electricity will therefore also grow and require an even greater portion of the family budget in future years. We may therefore expect that the rates paid for electric service will be subject to ever increasing scrutiny by the American residential consumer.

There is wide variation in the rates paid for residential service across the Nation. Table 9 gives some indication of the geographic pattern of residential rates as of 1963. We do not undertake here to justify or even to appraise these differences in rates, but a few words of explanation are in order. The lowest average rates are in the areas most directly affected by the Tennessee Valley Authority and the Bonneville Power Administration. In these areas retail rates are in the order of 30 to 35 percent below the national average and, as might be expected, customer usages are the highest in the Nation. The availability of low-cost hydroelectric power developed as part of multipurpose river improvement programs with the low fixed charges inherent in Federal construction combined with a promotional rate program accounts for much of the difference. As will also be evident from table 9, the highest average rates in the continental United States are to be found in New England. Average rates in this area have been in the order of 15 percent above the national averages for a number of years. Here the remoteness from low-cost fuel, the existence of numerous small systems which in the past built many relatively small and inefficient generating units and the low per capita use of electricity are reasons which are often given for the higher rates.

The long-term trend in rates for residential electricity has been downward. At the present time rates are in the order of 15 percent less than they were in 1935, although for the past decade there has been a tendency for them to increase slightly. Since 1951 the total increase has been in the order of 8.0 percent although there has been practically no increase since 1960 and, in fact, the long-term trend toward lower rates has been resumed. Lower fuel costs have resulted in some announcements of substantial rate reductions in 1963, and the 1964 reduction in Federal income tax coupled with increased efficiencies as more of the large commercial generating units go into service has accelerated this trend.

The above discussion describes the geographic pattern of retail rates based on statewide averages. Behind these averages is to be found even greater variation from one city to another. Some indication of the extent of this variation is given in table 10, which lists the cities in 10 States served by private companies with the highest residential rates in the country for monthly usage of 250 kilowatt-hours and the cities in 10 States with the lowest residential rates for comparable service. The table also contains similar lists of cities served by public power enterprises. A glance at the table will show that the cities having the highest rates are scattered across most of the country and that the same is true of the cities having the lowest rates. There is, however, some tendency for the highest rates to be concentrated in the eastern half of the country whereas a number of the lowest rates, both public and private, are found in the southeast and far west.

Geographical rate patterns for commercial service are similar to those for residential service. Those areas having the highest residential rates also tend to have the highest commercial rates and the areas having the lowest residential rates tend to have the lowest commercial rates. This is also true of industrial rates although the differences appear less pronounced, presumably because of the greater intercompany and inter-area competition for these loads.

Trends in rates for commercial service have been generally the same as residential rate trends. The long-term trend has been downward and, although rates moved up slightly during the decade of the 1950's, the downward trend was resumed in 1962.

Average industrial rates, at least for loads of 150 to 1,000 kilowatts, have increased continuously since World War II. As of 1963, industrial rates for loads in this range were 15 to 20 percent higher than in 1940 and 5 to 10 percent higher than in 1935. There is as yet no indication of a reversal of this trend.

Electric power is sold at wholesale for resale under a wide variety of terms and conditions. The most significant and most common type of wholesale

TABLE 9

State Average Typical Residential Bills and Rank of States From Low to High, Jan. 1, 1963

(Cities of 2,500 population and more)

Rank				Bills		
250 kwh	500 kwh	750 kwh		250 kwh	500 kwh	750 kwh
1963	1963	1963	State	1963	1963	1963
			United States	$7.48	$10.64	$14.65
3	4	4	Alabama	5.37	8.34	11.01
51	51	51	Alaska	10.51	15.60	21.02
36	40	35	Arizona	7.89	11.52	15.38
34	36	28	Arkansas	7.84	11.34	14.86
16	14	10	California	6.93	9.74	12.86
23	23	24	Colorado	7.43	10.40	14.56
41	41	41	Connecticut	8.29	11.56	16.23
44	34	43	Delaware	8.51	11.20	16.24
14	42	38	District of Columbia	6.80	11.59	16.09
38	44	39	Florida	7.97	12.09	16.21
6	6	7	Georgia	6.30	8.88	11.72
47	50	50	Hawaii	8.88	13.45	18.48
11	8	5	Idaho	6.74	9.23	11.45
33	29	25	Illinois	7.79	10.67	14.62
26	21	21	Indiana	7.56	10.27	14.31
40	38	41	Iowa	8.11	11.43	16.23
15	15	19	Kansas	6.83	9.80	13.88
9	9	12	Kentucky	6.68	9.38	13.17
25	35	37	Louisiana	7.53	11.27	15.63
50	47	48	Maine	8.99	12.31	17.47
37	48	45	Maryland	7.95	12.46	16.81
48	46	47	Massachusetts	8.89	12.16	17.43
22	17	23	Michigan	7.42	9.97	14.52
35	33	33	Minnesota	7.86	10.99	15.13
17	12	8	Mississippi	7.03	9.58	12.40
28	25	26	Missouri	7.62	10.51	14.68
24	31	20	Montana	7.51	10.73	14.03
5	7	9	Nebraska	6.27	9.01	12.58
9	20	13	Nevada	6.68	10.19	13.22
49	45	46	New Hampshire	8.96	12.14	17.08
30	27	32	New Jersey	7.63	10.57	15.04
32	26	29	New Mexico	7.68	10.52	14.87
43	49	49	New York	8.46	13.18	18.06
11	13	11	North Carolina	6.74	9.63	13.10
42	43	44	North Dakota	8.42	11.83	16.26
19	28	31	Ohio	7.26	10.65	14.99
39	24	30	Oklahoma	8.02	10.45	14.90
4	3	3	Oregon	5.61	7.10	8.99
21	16	17	Pennsylvania	7.33	9.82	13.82
46	37	40	Rhode Island	8.72	11.41	16.22
13	18	16	South Carolina	6.75	10.09	13.47

TABLE 9—Continued

Rank			State	Bills		
250 kwh	500 kwh	750 kwh		250 kwh	500 kwh	750 kwh
1963	1963	1963		1963	1963	1963
45	39	36	South Dakota	$8. 52	$11. 50	$15. 59
2	2	2	Tennessee	5. 00	7. 04	8. 29
27	30	27	Texas	7. 61	10. 72	14. 70
8	5	6	Utah	6. 65	8. 77	11. 48
31	32	34	Vermont	7. 66	10. 81	15. 22
28	19	18	Virginia	7. 62	10. 15	13. 83
1	1	1	Washington	4. 77	6. 01	7. 79
20	11	14	West Virginia	7. 29	9. 47	13. 31
7	10	15	Wisconsin	6. 63	9. 45	13. 35
18	22	22	Wyoming	7. 22	10. 28	14. 42

Source: Federal Power Commission, *Typical Electric Bills, 1963,* page VII.

service is firm power, i.e., power intended to have assured availability to the customer to meet his load requirements. Firm power is sold at wholesale by investor-owned enterprises to municipal, cooperative, and other investor-owned enterprises at rates which vary at least as much as the rates for residential service. Table 11, which shows high, low, and average rates charged by the large investor-owned companies in nine selected States, indicates that wholesale rates in these States vary from 0.35 cents per kilowatt-hour to nearly 2.1 cents per kilowatt-hour. To some extent the variations in wholesale rates between different regions reflect regional cost differentials so that the geographical pattern is similar to the pattern of retail rates, but the wide variations within regions cannot be so explained.

TABLE 10

Range of Highest and Lowest Typical Bills for 250 kwh of Residential Electric Service, by Type of Service and by State, United States, Jan. 1, 1963

Cities of 25,000 Population and More

Service From Private Companies [1]

Highest bill		Lowest bill	
City State	Amount	City State	Amount
Fitchburg, Mass	$9. 94	Madison, Wis	$4. 85
Terre Haute, Ind	9. 50	Spokane, Wash	5. 04
St. Petersburg, Fla	9. 46	Wichita, Kans	5. 25
Mason City, Iowa	9. 25	Portland, Oreg	5. 35
Hartford, Conn	9. 15	Valejo, Calif	5. 37
Manchester, N.H	9. 08	Fort Wayne, Ind.[2]	5. 40
Big Spring, Tex	9. 08	Birmingham, Ala	5. 51
Portland, Maine	8. 96	Las Vegas, Nev	5. 70
Joplin, Mo	8. 94	Atlanta, Ga	6. 10
New York (5 Boroughs) N.Y	8. 94	Covington, Ky	6. 16

See footnotes at end of table.

TABLE 10—Continued

Service From Public Power Entities [1]

Highest bill City, State	Amount	Lowest bill City, State	Amount
Belmont, Mass	$9.50	Eugene, Oreg	$3.00
Lafayette, La	8.50	Jackson, Tenn	3.50
Orlando, Fla	8.38	Decatur, Ala	3.50
Brownsville, Tex	8.27	Bowling Green, Ky	3.50
Columbia, Mo	8.00	Tacoma, Wash	3.55
Freeport, N.Y	7.80	Kansas City, Kans	4.95
Sioux Falls, S. Dak.[2]	7.75	Lincoln, Nebr	5.19
Fayetteville, N.C	7.70	Sacramento, Calif	5.36
Norwich, Conn	7.60	Rochester, Minn	5.40
Danville, Va	7.59	Jamestown, N.Y	5.43

[1] No more than one city is included from any one State.

[2] Part of the city served.

Source: Federal Power Commission, *Typical Electric Bills, 1963,* pages 1–86.

TABLE 11

Wholesale Rates: High, Low and Average Charge per Kilowatt-Hour for Firm Power Sales by Larger Companies, By State, 1962

State	High charge* (cents)	Low charge* (cents)	Average (cents)
Maine	2.09	1.08	1.48
Massachusetts	1.62	1.13	1.31
Florida	1.73	.65	1.04
Kansas	1.87	.55	.93
Kentucky	1.33	.64	.92
Iowa	1.63	.69	.86
California	1.54	.65	.82
Arkansas	1.37	.75	.77
Washington	.81	.35	.54

*Sales over 1,000,000 kwh.

Source: 1962 FPC Annual Report Forms 1.

The major significance of rates paid for power at wholesale is the fact that the cost of purchased power, whether by a public or private agency, must be covered in the retail rates charged to ultimate customers by the purchaser of such power. It is to be expected that as interconnection and coordination among systems becomes more and more extensive, the amounts of power transferred at wholesale will grow rapidly and the rates paid for this power will be of ever-increasing importance.

The promise of the future is for lower rates with the higher rate areas of today standing to realine the greatest reductions. It is obvious that a more closely knit system of power supply for the nation can provide more uniformity in rates to the benefit of all regions. The possibilities for reductions in rates by 1980 by reason of increased usage and fuller coordination of our power systems are discussed in detail in chapter 17.

CHAPTER 2

THE INDUSTRY'S PROSPECTS FOR GROWTH

The National Power Survey's projection of the industry's future visualizes increased dependence on electricity as a source of energy in the daily life of every American—in factories and offices, on farms, in transportation and recreation, and in homes in every section of the country. The United States will probably require approximately 2.8 trillion kilowatt-hours of electricity by 1980, or slightly more than three times the amount generated in 1960.[1] (See fig. 17.) To produce this energy a well interconnected and coordinated utility industry will require an installed capacity of about 525 million kilowatts, compared with about 200 million kilowatts of capacity in existence at the end of 1963.

Underlying our projection of the future market for electric power is the assumption that the industry, in its own enlightened self interest, will recognize the advantage of selling its product at the lowest possible price in order to promote the additional demand for electric service in a growing economy. One of the most encouraging aspects of the National Power Survey is the evidence it provides of a commitment by a growing number of power systems in the industry, to a far-sighted philosophy of maximum growth encouraged by reductions in rates and steady improvement in service.

In this chapter we are presenting estimates of load growth for the electric utility industry for the period until 1980. The estimates are the product of a cooperative effort by the Federal Power Commission and the industry, the latter acting through the Power Requirements Special Technical Advisory Committee.

It is well to emphasize that while the estimates are based on a careful assessment of past trends and projection of future loads, they are not a precise forecast of assured future consumption of electricity. Rather, the estimates are presented as a goal or target which may guide the comprehensive and imaginative long-range planning which is needed now to assure the best development of the Nation's electric power systems. Fulfillment of that goal is necessarily contingent upon many elements, including projections of the economic growth of the country as a whole, but to a large extent it will be determined by the industry's own course of action. In the face of increasingly strong competition from other energy industries, the electric power industry cannot afford to take its future growth rate for granted. One of the clearest lessons of economic history is that, in a dynamic and competitive market economy, no industry can afford to take its future growth rate for granted.

The 1980 Projection in Perspective

The projected increase of nearly 200 percent in electricity consumption from 1964 to 1980—corresponding to an increase of 233 percent over 1960, which is the base year for most of the projections in this report—may be compared with the estimated rise of about 40 percent in the Nation's population during the 16-year period and an increase of perhaps as much as 95 percent in our gross national product (GNP).[2]

Implicit in this growth projection is a rise in the total consumption of electricity on a per capita basis from about 5,400 kilowatt-hours in 1963 to approximately 10,600 kilowatt-hours in 1980. Expressed in relation to GNP, which is an all-embracing standard of the economy's performance, the increase is from an estimated 1.7 kilowatt-hours of electricity per dollar of GNP this year to about 2.6 kilowatt-hours in 1980, as compared with only 0.7 kilowatt-hours in 1940. The projected increase in electric energy consumption therefore implies more rapid growth than would result from paralleling population or income growth. The projection as-

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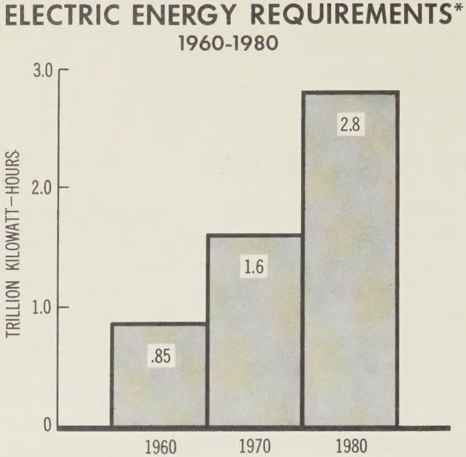
[1] The National Power Survey's projections are for the contiguous United States alone and do not include the states of Alaska and Hawaii which are not electrically connected with the other 48 States. Interconnection with Alaska is a possibility of the future.

[2] Assuming average growth of about 4 percent per year in terms of constant value dollars.



*Includes Industrial In-Plant Generation

FIGURE 17

sumes a continuation of the marked intensification in the Nation's use of electricity.

The growth in the total use of electricity in the United States has been remarkably steady throughout the industry's 80-year history, with usage doubling approximately every 10 years. The projection of 2.8 trillion kilowatt-hours of electricity in 1980 corresponds to an average growth rate of 6.3 percent a year in the two decades from 1960 to 1980. At this rate, production would double in about 11 years, reflecting recent evidence of a mild slackening in the industry's growth rate.

It is of some interest to compare the growth in use of electric energy in the United States with the growth in consumption of natural gas. The gas industry is the power industry's principal competitor. When Edison invented the incandescent electric lamp, it displaced gas lamps. Electric cooking competes with gas cooking, and electric water heating with gas water heating. Increasingly there is competition between the two for space heating and air conditioning. In industrial operations gas and electricity are often alternatives for process heat and other uses.

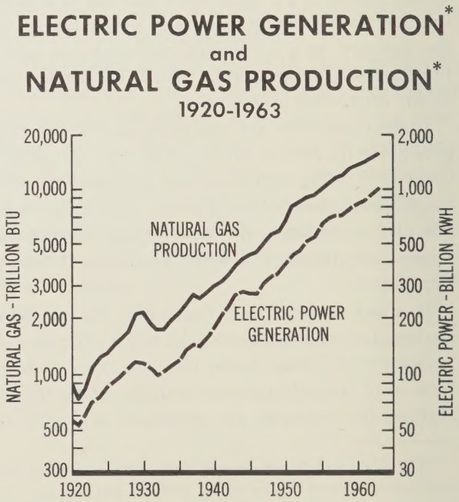
Figure 18 shows that the patterns of growth in use of gas and electric energy have been remarkably similar since 1920. The chart has logarithmic scales so that equal rates of growth result in parallel lines. It will be seen that throughout this period the growth patterns of gas and electric use have been almost indistinguishable.

The broad trend of energy use in the United States from 1920 to 1960 and the projections for 1980 are shown in table 12, both in terms of total energy units and the share provided by electricity.

The projections assume that electricity will increase from 20 percent of total energy consumed in 1960 to somewhat over 30 percent by 1980. To reach the latter figure, electricity must account for about 45 percent of the increment in total energy use from 1960 to 1980. Some increase in electricity's share of the total energy market is probably inherent in the overall growth of the economy, but the full increase implied by these projections will be realized only if the electric utility industry succeeds in selling important new uses of electricity to individuals and businesses, and at the same time makes electricity more attractive, relative to other energy forms, in terms of price and service.

How the Projection Was Established

The growth potential of the electric utility industry is continuously studied by the Federal Power Commission and estimates of future loads and capacity requirements have been regularly published for many years. The largest power systems—about 200 altogether, accounting for 97 percent of the total utility generating capacity in the country—annually submit forecasts of energy requirements



*Excludes Alaska and Hawaii

Source: American Gas Association Publications for Gas Data

FIGURE 18

TABLE 12

Actual and Projected Energy Use in United States,[1] 1920–80

Year	Energy units [2]		Electric power (percent of total)
	Total	Electric power [3]	
1920.......	19, 820	2, 300	[4] 11. 5
1940.......	23, 900	2, 900	[4] 12. 2
1960.......	45, 000	9, 000	20. 0
1980.......	82, 000	25, 100	30. 5

[1] Excludes Alaska and Hawaii.

[2] Energy unit used is a trillion Btu.

[3] Includes fossil fuel, water power, and nuclear energy.

[4] The small percentage increase of 1940 over 1920 reflects the great decrease in number of Btu needed to create a kwh of electricity during that period.

and peak loads for the next 4 years. The annual Power System Statements submitted to the Commission from about 2,500 electric utility systems provide detailed information on energy distribution and numbers of customers and there is a comparable flow of information to the Commission from industrial establishments with generating facilities of their own. These basic data, which have been studied for trends over the years, are of course supplemented by appraisals of all foreseeable factors which may alter past patterns of growth. FPC field offices, with their detailed knowledge of the special facts concerning growth prospects in their respective areas, have played a particularly important role in making electric power projections.

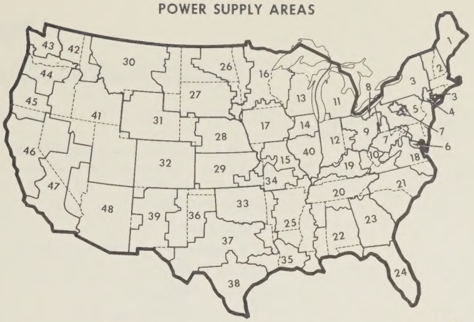
The load growth projections for the National Power Survey began with the assembly of data in each of the 5 field offices for the 48 Power Supply Areas and 8 FPC Statistical Regions into which the contiguous United States has been divided.

Figure 19 shows the way in which the 48 contiguous States are divided into 48 power supply areas, 16 coordination study areas, 8 statistical regions, and 4 sectors. Not shown is the East Zone which includes the Northeast, South and North Central Sectors, and the West Zone which is the same as the West Sector.

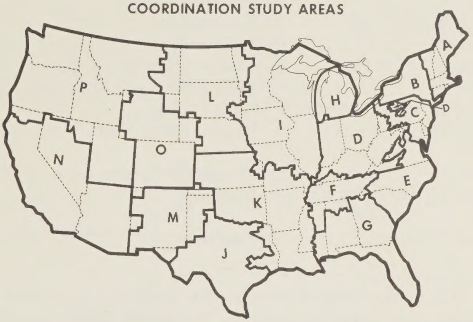
Table 13 presents the same information in tabular form.

The field offices were provided with a set of basic assumptions to guide their estimates of future loads. This information included Bureau of the Census estimates of population growth and household formation, an assumed annual increase in the GNP of 4 percent and other pertinent data. These were supplemented by a variety of intraregional data and trend statistics.

POWER SUPPLY AREAS



COORDINATION STUDY AREAS



FPC STATISTICAL REGIONS AND NPS COORDINATION STUDY SECTORS

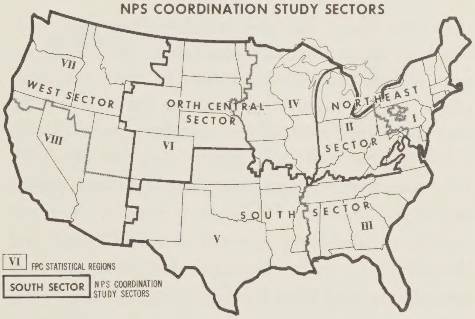


FIGURE 19

As a final step, the projections were presented for detailed evaluation by the Power Requirements Special Technical Committee, whose membership was selected from all segments of the industry and every region. The Committee reviewed these forecasts in depth, not only as to the postulates on which

TABLE 13

National Power Survey Areas, Regions, and Sectors [1]

Power Supply Areas 1 to 48	16 Coordination Study Areas	8 FPC Regions	4 Sectors
1, 2	A—New England	I Northeast Region	Northeast Sector
3, 4	B—New York		
5, 6	C—Pennsylvania-Jersey-Maryland		
7, 8, 9, 10, 12, 19	D—Ohio Valley	II East Central Region	
11	H—Lower Michigan		
18, 21	E—Carolinas-Virginia	III Southeast Region	South Sector
20	F—Tennessee Valley		
22, 23, 24	G—Southeastern		
37, 38	J—Texas Area	V South Central Region	
25, 29, 33, 34, 35	K—Middle South Area		
36, 39	M—New Mexico and Panhandle		
13, 14, 15, 16, 17, 40	I—North Central	IV North Central Region	North Central Sector
26, 27, 28	L—Upper Missouri Basin	VI West Central Region	
31, 32	O—Colorado-Wyoming Area		
30, 41, 42, 43, 44, 45	P—Northwest	VII Northwest Region	West Sector
46, 47, 48	N—Southwest	VIII Southwest Region	

[1] A further level of coordination is referred to in later chapters which combines the four sectors into two zones: East Zone, which includes the Northeast, South and North Central Sectors; and West Zone which includes the West Sector.

they were based, but also in comparison with various long-range forecasts which had been made on both regional and national bases by the power suppliers. This involved numerous contacts at the regional level by committee members meeting with FPC regional staff, with power suppliers and with other power survey groups. The projections adopted for the National Power Survey were the result of this collaboration between the FPC staff and the industry. In the Commission's judgment they provide a sound basis for the industry's long-range planning, although it is recognized, of course, that the projections will require constant updating in line with the ever-changing circumstances of the industry's and the Nation's growth.

Geographical Pattern

The projections of load growth for the eight FPC Statistical Regions are presented in table 14 [3] in terms of kilowatt-hours of output and coincident peak demand in each region.

In 1960, about 58 percent of the Nation's electric utility output was generated in Regions I, II and III, which include most of the area east of the Mississippi River. By 1980, this share may decline to 56 percent. This change while not large reflects a continuing westward shift of population and industrial centers, in addition to the expected decline in the gaseous diffusion load of the Atomic Energy Commission plants in the eastern regions.[4]

The lowest projected increase—an average annual rate of 5.8 percent—is shown for Region II, the heavily industrialized middle Atlantic area. This lower rate is heavily influenced by the planned decline in AEC loads. If this load is excluded, the annual rate of increase for Region II is 6.3 percent. The highest increases, 7.6 and 7.2 percent per year from 1960 to 1980, are projected for Regions V and VI, encompassing the central farming and grazing sections, where an accelerating pace of industrialization is anticipated. The projected growth rate for Region VIII, embracing California, is almost as high—7.2 percent per year—and well above the national average of 6.5 percent.

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[3] Industrial generation is shown separately in the table and is not distributed by regions.

[4] Gaseous diffusion is the process used to increase the concentration of U-235 in nuclear fuels.

TABLE 14

U.S. Electric Power Requirements by Geographic Regions,[1] 1960–80

FPC statistical regions		1960 actual		1970 projected		1980 projected	
		Energy [2] (billion kwh)	Peak demand [3] (million kw)	Energy [2] (billion kwh)	Peak demand [3] (million kw)	Energy [2] (billion kwh)	Peak demand [3] (million kw)
Electric utilities:							
I	Northeast Region	148	27. 5	271	49. 4	472	86. 6
II	East Central Region [4]	147	24. 8	263	44. 7	453	78. 1
III	Southeast Region [4]	148	26. 0	296	52. 3	548	97. 9
IV	North Central Region [4]	89	16. 7	164	31. 0	299	56. 9
V	South Central Region	78	16. 2	177	36. 6	336	69. 0
VI	West Central Region	16	3. 1	35	6. 8	64	12. 4
VII	Northwest Region	61	10. 2 0.6T	121	21. 1	224	39. 6
VIII	Southwest Region	74	13. 5	157	28. 2	297	52. 7
Total utility		761	138. 0	1, 484	270. 1	2, 693	493. 2
Industrial establishments:							
Industrial in-plant generation		85		105		127	
Total		846		1, 589		2, 820	

[1] Excludes Alaska and Hawaii.

[2] Kilowatt-hour output.

[3] Coincident peak demand for each region.

[4] 1960 figures for these regions include AEC gaseous diffusion plant loads as follows:

	Energy (billion kwh)	Peak demand (million kw)
Portsmouth Plant (Region II)	17. 1	2. 0
Oak Ridge Plant (Region III)	15. 1	1. 7
Paducah Plant (Region IV)	6. 5	0. 7
(Region III)	12. 2	1. 5

Since it appears that these loads will either remain constant or decline, their inclusion depresses the rates of growth derived from these figures.

Source: Advisory Committee Report No. 13, table 1 revised.

A number of factors account for the projected regional variations, including the current prospects for industrialization, supplies of natural resources, availability and prices of competitive fuels, cost of electricity, and the assumed level of requirements of production facilities of the Atomic Energy Commission. The latter requirements are projected to decline about 10 percent to approximately 50 billion killowatt-hours by 1980.[5] This decline will be centered in Regions II and III. As shown in table 15, the growth rates for these two regions are significantly higher when AEC requirements are excluded.

The Industry's Dynamic Role in a Growing Economy

In projecting a three-fold growth in electric power consumption between 1964 and 1980, the National Power Survey is not simply charting the industry's growth potential. The industry's growth is inseparable from that of the U.S. economy; one nourishes the other.

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[5] The AEC gaseous diffusion plant loads are being cut by 40 percent, in a series of steps from July 1964 to October 1967, but are expected to be restored to the projected levels by 1980.

TABLE 15

Rates of Increase in U.S.[1] Electric Power Requirements

FPC statistical region	Increase in generation: Percent increase 1960–70	Increase in generation: Percent increase 1970–80	Average annual increase: 1960–70	Average annual increase: 1970–80
Electric utilities:				
I Northeast	83.1	74.2	6.24	5.72
II East Central [2]	78.9	72.2	6.00	5.60
III Southeast [2]	101.4	85.1	7.26	6.36
IV North Central [2]	82.2	82.3	6.20	6.20
V South Central	126.9	89.8	8.56	6.63
VI West Central	118.8	82.8	8.15	6.23
VII Northwest	98.4	85.1	7.10	6.36
VIII Southwest	112.2	89.2	7.82	6.60
Total utility	95.0	81.5	6.92	6.15
Industrial establishments:				
Industrial in-plant generation	23.5	21.0	2.14	1.92
Total	87.8	77.5	6.52	5.92

[1] Excludes Alaska and Hawaii.

[2] Figures for these regions reflect the anticipated small decline in AEC gaseous diffusion plant loads expected at the time the load forecasts were prepared and referred to in table 14. If the effects of such loads are excluded the figures are as follow:

	Increase in generation: Percent increase 1960–70	Increase in generation: Percent increase 1970–80	Average annual increase: 1960–70	Average annual increase: 1970–80
Region II excluding Portsmouth Plant	90.8	76.6	6.74	5.86
Region III excluding Oak Ridge and Paducah Plant	126.7	92.6	8.54	6.79
Region IV excluding Paducah Plant	90.4	85.4	6.66	6.38

The electric utility industry has filled, and must continue to fill, an important role in channeling the nation's productive resources into more efficient uses. As an auxiliary and, indeed, a breeder of economic growth, the industry has furnished a rising proportion of the country's energy requirements as manual effort has been replaced by inanimate energy. The industry has promoted new markets for its services at prices which, over the long term, have steadily been lowered, thus encouraging the substitution of electrically-powered equipment for manual labor. The expanding use of energy-consuming capital equipment has been a principal source of improvement of national productivity and a stimulus to economic progress.

The industry's impressive growth performance is shown by the doubling of its own output every 10 years, whereas in the economy as a whole real output has doubled about every 20 years.

During the decade of the 1950's the industry accounted for 5 percent of the increase in the Nation's output of goods and services. Although the industry produced only 1¼ percent of that output at the start of the decade, its share in the gross national product now amounts to about 2½ percent, and it continues to account for a much higher proportion of each year's increment in GNP. Moreover, in recent years the industry, which is one of the most capital-intensive of all industries, has been responsible for somewhat over 10 percent of total plant and equipment outlays of American businesses.

Looking beyond the performance of the industry itself, we can see another aspect of the industry's contribution to overall economic growth. Electrification has had an enormous and far-reaching impact on other industries and on the living standard of people in every walk of life. Just as the automobile would have remained an invention of limited practical value if the oil industry had not supplied low-cost liquid fuels, so would numerous other inventions and productive processes have been stillborn without the wider availability of electricity at lower and lower cost.

In the future, as in the past, the availability and cost of electric power will continue to have a pervasive influence on the pace of our overall economy growth, although the effects will probably not continue to be as marked or dramatic as when electricity first came into general use.

Major Use Categories

A breakdown of the load projections into major use categories indicates, at least in a general way, how the projected growth may be achieved. (See tables 16 and 17.) For example, the breakdown suggests that the residential market will continue to be the fastest growing market in the period ahead. The projected increase of 555 billion killowatt-hours in residential use—corresponding to an average increase of more than 150 percent per customer—highlights the potential for residential space heating and air conditioning and for greater use of electricity for appliances and improved lighting. Industrial consumption, the largest of all the utility use categories shown, is projected to increase by 768 billion kilowatt-hours, representing a slower growth rate than for residential. Commercial consumption may grow at about the same rate as industrial, adding some 309 billion kilowatt-hours to existing loads by 1980. The projected increases are substantially lower in the farm category, partly because of the expected further decrease in the number of farms.

New Uses

In long-range projections of electric use it is difficult to reflect with assurance the development of new products and uses which may create large additional power demands or, on the other hand, to allow for new equipment with increased efficiency which may be an offsetting factor. The Report of the Power Requirements Committee observed "that almost invariably utility long-range forecasts are low. There is an historic pattern of new, ever increasing uses of electric energy which are not now envisioned. Rapid advances in power technology are occurring and are in prospect—which the Committee is confident will improve the position of electricity in competition with other fuels."

Perhaps the best illustration of a potential development that could substantially alter future projections is an improved electric battery, which would open up a whole new vista of electric power growth. The potential of the market is large even if only a moderate segment of our vehicles were battery operated. The magnitude of the opportunity can be gauged from the fact that supplying the automotive needs in this country with electricity would roughly double the industry's present output. Battery-operated vehicles are common today for specialty uses such as golf carts and electric industrial trucks. Improvements in battery weight, life, and costs—of a magnitude which does not seem at all unattainable—would make possible a tremendous multiplication of battery-operated appliances and vehicles. Because batteries can be recharged in offpeak hours they offer loads which are ideal for improving system load factors. They would thus provide an opportunity for solidly based attractive rates.

Success in promoting electric automobiles for everyday use would not only increase the market for electricity but could also go a long way toward eliminating what is perhaps the largest single source of air pollution in our metropolitan centers. Considerations of health and convenience might well justify a price premium for electric vehicles.

The development of the electric automobile for urban transportation before 1980 would appear to warrant a substantial amount of additional research. Relatively little has been spent on battery research in the past, although the pace has been stepped up in recent months and should be further accelerated. There is every reason for the industry to direct more of its research efforts toward such a break-through, which would raise the horizons for electric power growth.

TABLE 16

Annual Electric Power Requirements by Categories of Use, 1960–80

Category of use	1960 actual		1970 projected		1980 projected	
	Billion kwh	Percent total U.S.	Billion kwh	Percent total U.S.	Billion kwh	Percent total U.S.
Electric utilities:						
Residential (nonfarm)	174	22. 7	373	25. 2	729	27. 1
Irrigation and drainage pumping	10	1. 3	17	1. 1	25	0. 9
Other farm [1]	22	2. 9	35	2. 4	52	1. 9
Commercial	121	15. 9	241	16. 2	430	16. 0
Industrial [2]	330	43. 4	615	41. 5	1, 098	40. 8
Street and highway lighting	7	0. 9	13	0. 9	22	0. 8
Electrified [3] transport	5	0. 7	6	0. 4	6	0. 2
Other uses	22	2. 9	42	2. 7	71	2. 6
Losses and unaccounted for	70	9. 3	142	9. 6	260	9. 7
Total utility requirements	761	100. 0	1, 484	100. 0	2, 693	100. 0
Industrial establishments:						
In-plant generation [4]	85	....	105	....	127	....
Total	846	....	1, 589	....	2, 820	....

[1] Includes farms actually used for farming; other residential uses in farming areas included under "Residential."

[2] Includes AEC loads which are expected to decline. See table 14.

[3] This projection reflects recent U.S. experience trends but could be far too low if the progress of electrified transport in other countries should prove a guide to future use in this country.

[4] Excludes industry sales to electric utilities.

Electrification of rail or other public transportation is another illustration of increased use which could enable the industry to exceed the growth rate that has been projected. The indicated increase of less than 1 percent per year for electrified transportation reflects the slow development of this market in recent years. Today, class 1 railroads, which are now classified as those with annual operating revenues exceeding $3 million, use about 1.6 billion kilowatt-hours of energy annually on their electrified lines. In contrast, 50 billion kilowatt-hours would be used annually if these large trunk-line railroads were electrified, not to mention possible urban transportation loads. Thus, if the projections made for the National Power Survey reflected more complete utilization of the technological opportunities for electrification of railways and urban mass transportation systems, they would require a substantial upward revision. Such optimism cannot be justified on the basis of the recent pace of electrification of transportation facilities, yet it is not beyond realization by 1980.

The recent enactment of Public Law 88–365 provides for expenditure of Federal funds up to $160 million annually for assistance to cities in planning and undertaking solutions to congested mass transportation problems through the medium of rapid transit systems. While the magnitude of the financial assistance is too limited in itself to assure major inroads on this problem, it will constitute a guiding stimulus to many cities to begin a conversion process which has too long been deferred. San Francisco has taken the lead for the Nation among cities which do not now have major mass transit systems. In 1962 the use of revenue bonds in the amount of $792 million was approved by the voters

TABLE 17

Projected Rates of Increase of Electric Power Requirements by Categories of Use, 1960–80

Category of use	Increase in power Requirements 1960 to 1980		Average annual increase, percent	Number of years to double consumption
	Billion kwh	Percent		
Electric utilities:				
Residential (nonfarm)	555	319	7. 4	10
Irrigation and drainage pumping	15	150	4. 8	15
Other farm [1]	30	136	4. 4	16
Commercial	309	255	6. 5	11
Industrial	768	233	6. 2	11
Street and highway lighting	15	214	6. 2	12
Electrified transportation [2]	1	20	0. 9	80
Other deliveries to ultimate customers	49	223	5. 9	12
Losses and unaccounted for	190	271	6. 7	11
Total utility	1, 932	254	6. 5	11
Industrial establishments:				
In-plant generation [3]	42	49	2. 1	34
Total	1, 974	233	....	....

[1] Includes farms actually used for farming; other residential uses in farming areas included under "Residential."

[2] See footnote 3 in table 16.

[3] Excludes industry sales to electric utilities.

of the city of San Francisco and Alameda and Contra Costa Counties for the construction of a 75-mile rapid transit network. This project is scheduled for completion in 1971.

Any reduction in the cost of electricity, while unlikely by itself to overcome all of the formidable obstacles to mass conversion from ordinary surface transportation to rapid transit, will nevertheless contribute toward improving the economics of the problem and tend to increase the likelihood of conversion in many parts of the country. The urban transportation dilemma presents us with no less than a choice between saving our cities and the cultural and commercial attractions which they alone can provide, or letting them decay as we build our daily lives entirely around our own neighborhoods with all the limitations and the sameness which confinement to one's own parish entails.

Apart from the encouragement of urban electric transit systems, lower costs of electricity will also tend to hasten the electrification of inter-city transportation. A major trend toward electrified public transportation would of course be a boon to electrical equipment manufacturers, who would then be in greatly improved position to compete for the large foreign markets for such equipment.

In Europe both urban and interurban rail transportation are electrified to a much greater extent than in the United States and constitute about 3.5 percent of the total electric energy load. The consumption of electricity in Europe for traction use is increasing at an average annual rate of 6.5 percent which compares with a rate of increase in total use of electricity of 7.6 percent. Russian electrified transportation consumes some 23 billion kilowatt-hours amounting to over 5 percent of its total consumption of electric energy. Japan is building a new electrified 320-mile railway line from Tokyo to Osaka. The railway is planned for train speeds up to 157 miles an hour.

More and better lighting of streets and highways constitute opportunities for expansion in electric use

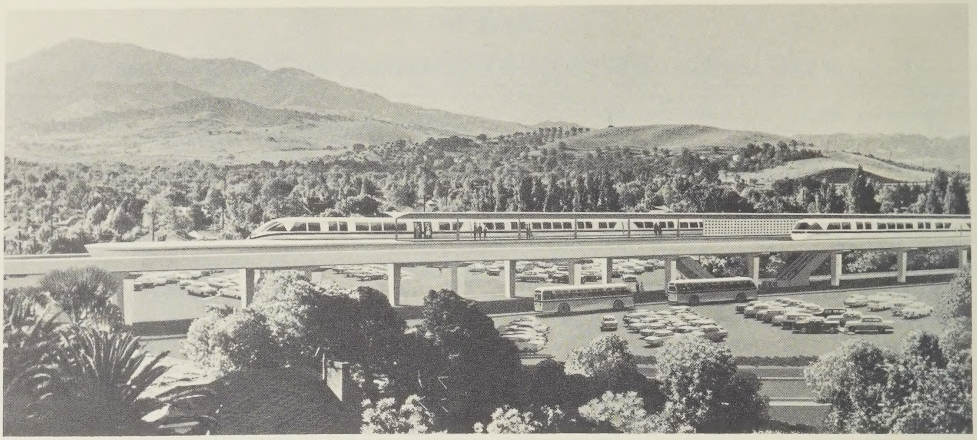

Figure 20 *An artist depicts a suburban station on the San Francisco Bay Area Rapid Transit System. Work on this $1 billion project, scheduled for substantial completion in 1970–71 is just getting underway. A key link in this 75 mile system will be a 4-mile underwater tube between San Francisco and Oakland, the longest in the world. Power for this system will be supplied at 34½ kilovolts and the estimated peak load will be 100,000 kilowatts.*

which can contribute greatly to the public welfare and especially to public safety. Illumination of some of our interstate and other main arterial highways, particularly at interchanges and other places of needed caution, has proven beneficial to highway safety. Its expanded use should be encouraged. Adequate lighting for city streets and suburban areas reduces traffic hazards and discourages criminal activities.[6] Thus, this sector of power use may have the potential for much faster growth than shown in our projections.

The recovery of resources may demand much greater use of electricity in future years. High-grade deposits of many of our minerals are limited but lower grade deposits are frequently extensive. The key to transforming many of these low-grade deposits into useful raw materials could very well be mass mining methods employing electric energy. Any reduction in the cost of energy tends to make it economically feasible to recover more of these low grade mineral deposits; conversely, the pace of depletion of high-grade deposits will inevitably require utilization of lower-grade sources at increased energy expenditures for mining and processing. The same is true of high-quality deposits which are difficult of accessibility. Strip mining for coal and other resources requiring the removal of vast amounts of waste materials to reach veins of valuable ores has become economically feasible through the development of massive excavating equipment employing electric motive power.

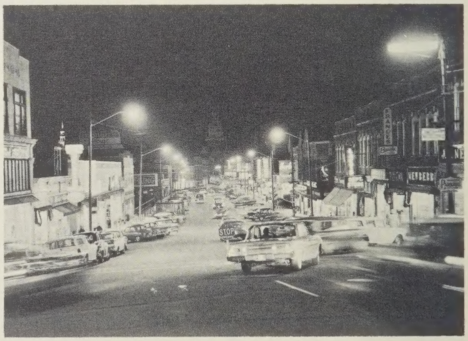

Figure 21 *Brightly lighted Central Avenue of Dover, New Hampshire is an attraction to shoppers and affords safety to pedestrians and motorists alike.*

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[6] A report, *The Federal Role in Highway Safety* (House Document No. 93, 1959), concluded that modern street lighting produces many social gains. In addition, a circular memorandum dated April 15, 1964, from the Federal Highway Administrator lists the installation of highway lighting among the typical Federal-aid projects which deserve a high priority of attention in accident prevention programs.

As high-quality water supplies dwindle in relation to expanded requirements, we must also count on large electric power requirements for water treatment, desalination and the transportation of water between watersheds. Our electric energy use will thus grow not only with population and rising standards of living (offset in part by more efficient utilization) but with requirements of greater energy to recover more and lower-quality mineral and water resources.

Residential Load Growth

Residential use of electricity is the category in which continuity of growth has been especially marked. This category now accounts for about 30 percent of all electric energy sold in the United States. Reported residential sales have grown in every year except 1933, when the decline was scarcely 1 percent. Total sales of all electric energy increased each year except 1930, 1931, and 1932 when they dropped below the preceding year, due to a large decline in industrial usage brought about by the great depression.

Residential consumption began with the incandescent lamp, but other uses soon developed. The earliest widely used appliance was the electric iron. Early motor-operated household equipment included fans, sewing machines, and vacuum cleaners. Today the household uses of electricity are numbered in the hundreds, although it may be noted that relatively few completely new utility appliances of major load significance have come onto the market within the last two decades or so.

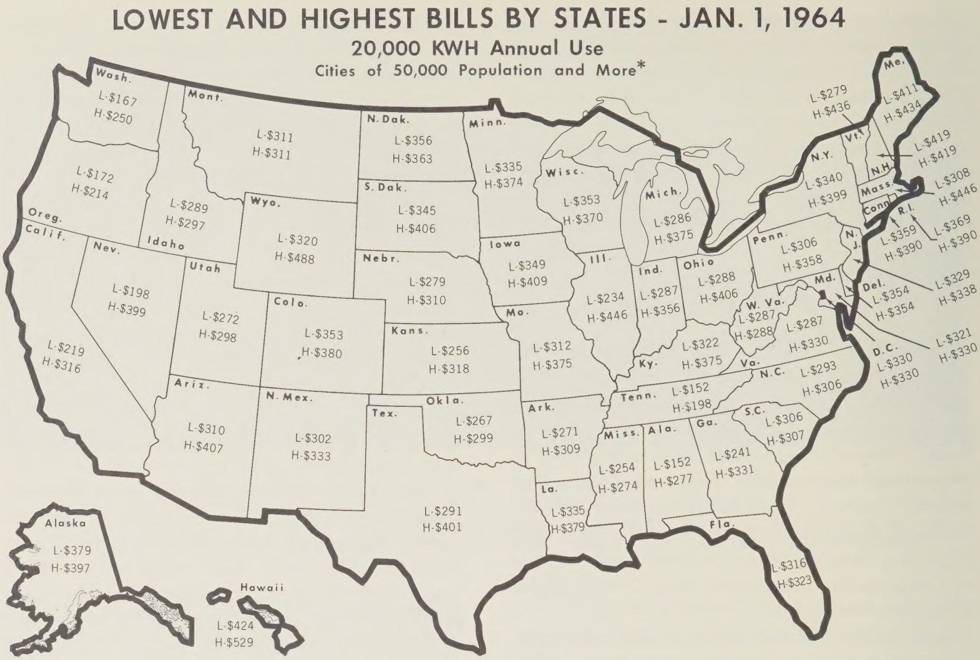
In the next 20 years space heating and air conditioning will be key factors in residential load growth. No technological breakthrough is needed. The space-heating market is one of unrelenting competition to which the alternate heating fuels industries are committing major promotional efforts. To achieve the industry's announced target of 19 million electrically heated homes by 1980 will require considerable technological and promotional effort, but an important element will be the ability of the industry to reduce costs and rates. Figure 22 shows lowest and highest bills by States as of January 1, 1964, for 20,000 kilowatt-hours annual use, which is typical for an all-electric home.

The potential market for electric heating of homes is very large, since only slightly more than 1 million homes are now fully electrically heated. The average annual use of about 20,000 kilowatt-hours of electricity in homes with electric heating and cooling contrasts with an average of 4,100 kilowatt-hours in nonelectrically heated homes. If we assume that one home in four will be electrically heated in 1980—which is consistent with the projection of 19 million electrically heated homes—this heating load would account for 225 billion kilowatt-hours of electricity annually, over 30 percent of the total consumption projected for nonfarm residential use.

The potentialities for residential air conditioning are also bright because that market too is in a comparatively early stage of penetration by the electric utilities. Only 10 million of the 55 million homes in this country now have means of air cooling and most of these are only partially cooled. In the not very distant future, most new homes in the middle or higher price range in nearly all parts of the country—and even most low-cost homes in hot and humid regions—are likely to be centrally air conditioned. The electric heat pump, which cools a home by the refrigeration process and automatically reverses itself to produce warm air for heating will aid in the capture of electric loads for heating and air conditioning. The heat pump offers an excellent prospect of reducing the cost of electric heating and cooling. It is already finding an expanding market, particularly in climates having average winter temperatures of 40° or above, and the industry is moving forward with the additional research required to achieve further needed improvements in its design and performance. The gas heat pumps may, of course, also benefit by such improvements.

The National Power Survey's load estimates are predicated on an expansion of the utility industry's research and marketing programs. These programs, in addition to promoting the all-electric home, stress adequate wiring and service entrance facilities having a minimum of 200 amperes capacity to accommodate increased household appliance loads. Many utilities have active programs to assist owners of older homes in the improvement of their electrical installations to permit safe and satisfactory use of the many higher capacity appliances which now have become normal household necessities.

Greater future use of electricity for appliances is indicated by the success in recent years of a number of new and improved designs in household electric



LOWEST AND HIGHEST BILLS BY STATES - JAN. 1, 1964

20,000 KWH Annual Use

Cities of 50,000 Population and More*

Wash. L-$167 H-$250
Mont. L-$311 H-$311
N. Dak. L-$356 H-$363
Minn. L-$335 H-$374
Oreg. L-$172 H-$214
Idaho L-$289 H-$297
Wyo. L-$320 H-$488
S. Dak. L-$345 H-$406
Wisc. L-$353 H-$370
Mich. L-$286 H-$375
Calif. L-$219 H-$316
Nev. L-$198 H-$399
Utah L-$272 H-$298
Colo. L-$353 H-$380
Nebr. L-$279 H-$310
Iowa L-$349 H-$409
Ill. L-$234 H-$446
Ind. L-$287 H-$356
Ohio L-$288 H-$406
Penn. L-$306 H-$358
N.Y. L-$340 H-$399
L-$279 H-$436
Vt.
Me. L-$411 H-$434
N.H. L-$419 H-$419
Mass. L-$308 H-$446
Conn.
R.I. L-$359 H-$390
L-$369 H-$390
N.J. L-$329 H-$338
Del. L-$354 H-$354
Md.
D.C. L-$330 H-$330
L-$321 H-$330
W. Va. L-$287 H-$288
L-$287 H-$330
Va.
Kans. L-$256 H-$318
Mo. L-$312 H-$375
Ky. L-$322 H-$375
Ariz. L-$310 H-$407
N. Mex. L-$302 H-$333
Okla. L-$267 H-$299
Tex. L-$291 H-$401
Ark. L-$271 H-$309
Tenn. L-$152 H-$198
N.C. L-$293 H-$306
S.C. L-$306 H-$307
Ga. L-$241 H-$331
Ala. L-$152 H-$277
Miss. L-$254 H-$274
La. L-$335 H-$379
Fla. L-$316 H-$323
Alaska L-$379 H-$397
Hawaii L-$424 H-$529

*At Least 3 Cities are Included for Each State Regardless of Population

L—LOW BILL H—HIGH BILL

FIGURE 22

equipment. The pace of these technological advances can be expected to continue and perhaps to create new sales markets for such equipment. Increased leisure time accompanying the trend toward a shorter workweek will also increase the desire and need for heavy as well as small appliances, and increased per capita income in the years ahead will accelerate the purchase of luxury as well as basic equipment. According to recent estimates less than 25 percent of the homes in America contain electric clothes dryers, and the same can be said with regard to dishwashers, home freezers, and water heaters (see table 18). Of course alternative fuels compete for some of these uses. In the future, an increasing number of homes will contain more than one of many of these electric appliances. Thus, the estimates of market saturation need to be interpreted with care. Indeed, families who already own one of these appliances, such as a room air conditioner, are often the most promising prospects for sales of additional units of the same equipment or for sales of larger-size models.

Substantially increased use can be predicted for such luxury conveniences as electrically heated walks and driveways, outdoor lighting for protection and decoration, well-equipped basement workshops, home elevators or inclinators, and numerous other electrically operated improvements which will add to the comfort and pleasure of daily living. The penetration of these product markets is susceptible to substantial acceleration by the industry's sales efforts.

The projections for 1980 contemplate a rise in average annual consumption per nonfarm residential customer from about 4,200 kilowatt-hours in 1963 to 10,000 kilowatt-hours. Considering that the 10,000 average has already been reached or exceeded in the TVA and Pacific Northwest regions, and in other individual areas served both by public and investor-owned groups, this goal may not look overly impressive; however, one should not be misled into thinking that it can be easily reached, particularly because of the large and growing number of apartment-dwellers who use less electricity than those living in single-family homes.

TABLE 18
Percentage of Homes with Heavy Electrical Appliances

Appliance	Percent of homes 1952	Percent of homes 1962
Air conditioner	1	15
Clothes dryer	3	20
Dishwasher	3	9
Food waste disposer	3	12
Home freezer	10	24
Range	23	39
Refrigerator	88	99
Television	41	93
Vacuum cleaner	58	77
Washer	75	82
Water heater	13	21

The Farm Market

The market for electric energy in the agricultural phase of our economy—the load categories of "Irrigation and Drainage Pumping" and "Other Farm" as presented in table 16 and 17—is geared primarily to growth in population and intensification of energy use in relation to the unit of food production. Another factor, the rate of territorial expansion of electric service in rural areas, was a foremost consideration in the three decades from 1930 to 1960. The dramatic expansion that occurred in this period, as summarized in table 19, resulted in increasing the number of farms served with electricity from less than 10 percent to nearly 100 percent service.

As the table shows, the number of farms declined heavily during the period, which reflects the magnitude of the transition from small farms requiring much hard labor to much larger highly mechanized and more efficient farms.

The modern successful farmer has adopted some of the methods of modern industry in order to bring about more efficient production at less cost and with less expenditure of labor. Electricity on the farm can be put to work in many ways—in handling materials, in milking, milk cooling, and other dairy uses, in grinding and mixing and conveying feed, in pumping water, and in filling silos. The farm workshop needs electrical equipment for repairs and improvements.

In the modern concept of farming, new ways of putting electricity to work are continually being sought. Aid in this effort is received from such programs as the electrified farm programs sponsored by the Extension Service and utility systems in many areas of the country. One good example is the program of the Tennessee Valley Authority, the objectives of which are fivefold: (1) to make the farm community more aware of the important role which electricity can play in the overall development of the farmstead; (2) to help individual farm families make long-range plans which utilize electricity on the farm and in the home to increase income and improve living standards; (3) to demonstrate through the use of selected Electrofarms the many ways which electricity can be used to save time and labor and increase efficiency; (4) to promote overall farm safety; (5) to strengthen the agricultural economy of the area through more careful planning and better farm management. Many electric utilities and cooperatives throughout the country, as well as various land grant colleges, are engaged in similar programs to promote expanded use of electricity on the farms.

TABLE 19
Increase in Electrified Farms

Year	Number of farms (in thousands)	Percent of farms with electricity
1930	6, 546	9. 9
1940	6, 350	30. 4
1950	5, 648	77. 2
1960	3, 949	96. 5
1962	3, 688	97. 6
1963	3, 573	97. 9

Source: Department of Agriculture; Rural Electrification Administration.

In the rural areas, power suppliers have found that aggressively promoted dusk-to-dawn flood lighting programs for barnyard areas can add attractive cumulative loads. Many of these power suppliers install and own the equipment and charge the user a flat fee for the service as part of the regular monthly bill. Such lighting applications could well add several billion kilowatt-hours of load by 1980.

FIGURE 23 *Attractive outdoor garden lighting, which adds to the amenities of outdoor living, is one of the many services which will, in the aggregate, help to increase system power loads in the future.*

The projected consumption of electricity per farm unit in 1980 is 16,000 kilowatt-hours, nearly three times the unit use in 1960. In contemplation of the large amount of motorized new farm machinery that is continually appearing, this forecast could well prove to be modest, particularly if improved battery power becomes practical for sustained mobile use.

While almost every American farm is electrified today, relatively few farms have three-phase service today, and this may be the key to capturing certain heavy-duty farm loads.[7]

While future load gains in agricultural use may not keep pace with the national average, these gains have been and will continue to be among the most significant in their beneficial effects toward improving the comfort, convenience, and general welfare standards of an important segment of our population.

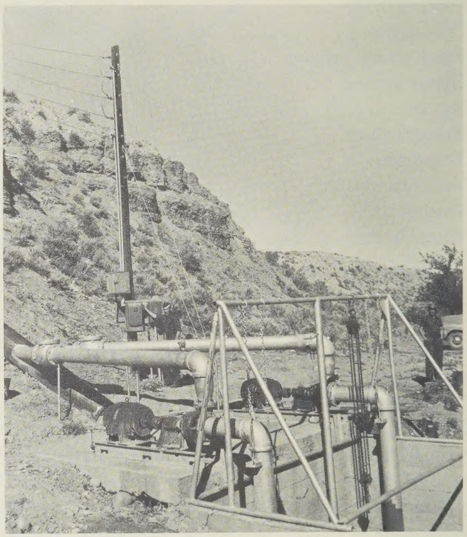


FIGURE 24 *Electricity has become an essential and dependable servant in the country's agricultural economy as typified by its use here for the pumping of water for irrigation.*

Industrial and Commercial Markets

Electric power for industry will continue to be the largest single use category requiring over a trillion kilowatt-hours annually by 1980. Much of this power will go to intensive users of electrical energy such as the aluminum and electro chemical industries. Commercial loads are expected to total an additional 430 billion kilowatt-hours a year.

These projections reflect growing automation as well as the substitution of electrical energy in many industrial heating operations now using gas, oil, or coal, with improvements in manufacturing costs and production control.

Load growth in the commercial markets is projected at 6.5 percent per year, somewhat higher than

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[7] Single-phase alternating current service requires two wires (one single phase wire and a ground wire). Voltage oscillates at 60 cycles per second. Three-phase service uses 4 wires (3 "single-phase" wires and a ground wire), with three corresponding sets of oscillations in voltage, which are timed to reverse polarity at equally spaced intervals. Three-phase service thus requires a heavier investment in conductors and other distribution equipment than is needed for single-phase service, but it requires a smaller investment in the heavy power-using equipment. Its steadier voltage and current make it by far the more economical type of power supply for such equipment. Consequently, while most residential loads are single-phase, industrial loads require three-phase service.

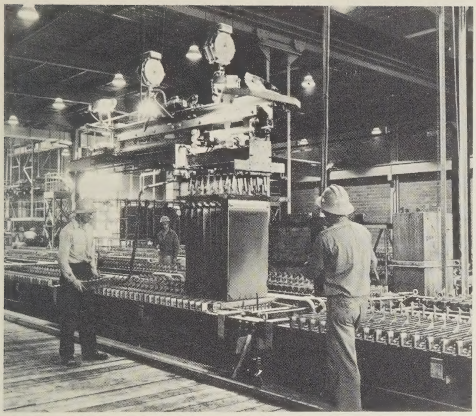

FIGURE 25 *The use of electricity for the processing of manganese as depicted here and for other primary metals such as titanium and aluminum, is a source of much potential growth in industrial loads.*

the 6.4 percent for the industrial market. Our estimates allow for an accelerated expansion of lighting, air conditioning and electric space heating, more installations of electric stairways, much more electric office equipment, and the growth of electric cooking in restaurants and institutions. This is an area of load growth for which the competition is already particularly keen.

Although the cost of electricity may be a relatively small component in the total cost of manufacturing in many industries, the aggregate demands are important, and are becoming more so as uses expand beyond the primary manufacturing needs. The rapid growth in the lighting and air conditioning of industrial plants to improve working conditions and the requirements for critical temperature and humidity control in many new industries will be adding substantially to future loads. While cost reductions in electric energy will encourage the consideration of auxiliary needs the cost of the required electric equipment may be much greater than the cost of the energy consumed. In this instance the equipment costs may have a greater impact on electrification than the cost of energy itself.

Substantially expanded electric loads will develop in existing industries, particularly the aluminum, steel, glass, plastics, and chemical industries. Infant industries, stemming from the rapid unfolding of new materials and new processes following World War II, will be making stronger demands for energy. For example, the potential market for the manufacture of titanium, a promising newcomer to the group of structural metals and noted for a high strength to weight ratio and temperature resistance is suggested by the fact that twice as many kilowatt-hours are required to produce a ton of titanium as are required per ton of aluminum or magnesium.

Air conditioning of commercial buildings is rapidly becoming a necessity in almost all areas of the country and thus affords a large and growing market. Greater use of electricity for outdoor signs and display lighting as well as for interior store lighting will be essential in urban life of the future. Increased outdoor lighting will be used for organized and institutional recreation as the rapid trend toward night sports spreads from baseball and football to many of the minor outdoor sports such as tennis, and swimming, and even to golf. Since these loads would nearly always occur during off-peak hours, utilities can afford to encourage further use by adopting promotional rates.

Self-Generation of Electricity by Industry

Many industrial concerns in the early days of utility service found it advantageous to operate their own generating plants, particularly where there were opportunities to utilize waste process heat for electric energy generation. While some self-generation among industries has continued, the amount in relation to total industry use has declined from more than 50 percent prior to World War I, to 30 percent in 1920, 20 percent in 1940, and only 10 percent today. In large measure this trend reflects the economies of scale in central station service. As the electric power industry continues to reduce the cost of electric energy, industrial enterprises with few exceptions will find it increasingly difficult to justify self-generation of their power requirements. In our projections for industrial generation, an average annual rate of increase of only about 2 percent is assumed for in-plant generation, less than one-third of the projected rate of growth for utility sales to industrial customers. Thus, the inplant industrial generation share of total national electric power consumption is expected to decline from 10 percent in 1960 to about 4.5 percent in 1980.

Summary and Conclusions

Starting from the vantage point provided by knowledge of the industry's past achievements and future plans, we have projected a possible tripling of the country's use of electricity by 1980. The achievement of this growth is contingent upon a continuing reduction in the price of electricity—a prospect which is encouraged both by the industry's earlier record and by the promise of continuing technological advances, as described in later chapters of this Report.

The eagerness of our modern industrial society to use more electricity as its price is reduced and its service quality improved has been demonstrated time and again in the past. In satisfying that demand the electric utility industry also discovered that load growth is in turn an important avenue for further reductions in unit costs and prices. The application of this experience provides the key to the electrical age of the future.

CHAPTER 3

FUELS AND FUEL TRANSPORT FOR ELECTRIC ENERGY

The electric power industry uses more than half of all the bituminous coal mined in this country, large volumes of natural gas and oil, and a growing amount of nuclear energy.

Fossil fuels were the basic energy source of 81 percent of the electricity generated in the United States in 1963. In order to meet the tremendous growth in the demand for electricity expected for the coming decades, our projections indicate that by 1980 the electric power industry will more than triple its 1960 demand for fossil and nuclear fuels and will be using annually some 500 million tons of coal, 4 trillion cubic feet of natural gas, 100 million barrels of residual oil, and 20 to 30 thousand tons of uranium for nuclear generation.

Fuel accounts for 15 cents of every dollar spent by utilities for electric power, with transportation comprising a significant part of the total fuel cost. The future demands for fossil and nuclear fuels involve such large quantities that competition and technological gains will most certainly result in reducing the cost of fuel at the source, and also the cost of moving it to market. Delivered fuel costs are expected to drop from a 1962 average national price of 26 cents per million British thermal units to 21 cents by 1980. These figures reflect anticipated reductions in fuel transportation costs and in some cases, the alternative of locating power plants at the fuel source and transmitting the electricity, rather than the fuel, to the load area.

This chapter reviews the major considerations affecting the supply and costs of fuels to electric utilities during the survey period. In making our appraisal of fuel supply and costs, we have drawn heavily on basic general energy studies conducted in recent years by Government and private sources and especially upon the reports submitted to the Commission by the Special Technical Advisory Committee on Fuels.

Total Fuel Requirements

The total use of fossil and nuclear fuel for electric power generation is projected to increase from 6,500 trillion Btu in 1960 to approximately 22,000 trillion Btu in 1980. The latter figure is equivalent to 900 million tons of coal with a heat content of 12,500 Btu per pound. The rate of increase of use for fuels projected by the electric power industry closely parallels the rate of growth we have projected in the National Power Survey; for 1980 both the loads and the fuel requirements are approximately 3⅓ times the 1960 level. Although the share of thermal sources (including nuclear) is expected to increase to 87 percent of total kilowatt-hours generated in 1980 as the share of hydroelectric power declines, continued progress in reducing fuel requirements per kilowatt-hour should offset the impact of the increased reliance on thermal sources.

The estimated total fuel requirements for thermal power generation, including nuclear fuel, by study areas is presented in table 20. These estimates reflect the reduced fuel requirements per kilowatt-hour of using the larger generating units with improved thermal efficiencies. The trend in fuel used in the typical area tends to follow the expected growth in the area's electrical loads. The major departures from this pattern occur in several areas of the Far West—L, N, O and especially P. These areas at present depend on hydroelectric sources for a major share of their generation but will become increasingly dependent on thermal sources for future growth as the availability of good undeveloped hydro sites diminishes. Some areas, of course, are expected to be moderate net importers or exporters of electricity generated at particularly favorable locations, including some mine-mouth alternatives and Canadian hydro. These sources are examined in chapter 15. The expected growth of fuel requirements therefore does not always coincide with the expected growth in load.

Fuel Availability and Use Trends

The overall outlook for fuel availability is favorable. We expect fuel supplies at prices close to present levels to be ample to meet the thermal electric demand for the life of generating plants installed by 1980.

TABLE 20

Fuel Requirements for Thermal Power Generation by Coordination Study Areas (See Fig. 19)

(Trillions of Btu)[1]

	Coordination study area [2]	1960 actual	1970 estimated	Percent increase 1960–70	1980 estimated	Percent increase 1970–80	Percent increase 1960–80
A	New England	286	530	85.3	900	69.8	214.7
B	New York	444	842	89.6	1,408	67.2	217.1
C	Pennsylvania-New Jersey-Maryland	658	1,057	60.6	1,716	62.3	160.8
D	Ohio Valley	1,156	2,124	83.7	3,489	64.3	201.8
E	Carolinas-Virginia	296	630	112.8	1,246	97.8	320.9
F	Tennessee Valley	469	837	78.5	1,390	66.1	196.4
G	Southeastern	447	1,019	128.0	1,931	89.5	332.0
H	Lower Michigan	252	498	97.6	908	82.3	260.3
I	North Central	872	1,526	75.0	2,608	70.9	199.1
J	Texas Area	348	772	121.8	1,219	57.9	250.3
K	Middle South Area	478	794	66.1	1,246	56.9	160.7
L	Upper Missouri Basin	66	106	60.6	234	120.8	254.5
M	New Mexico and Panhandle	86	158	83.7	252	59.5	193.0
N	Southwest	577	1,093	89.4	2,270	107.7	293.4
O	Colorado-Wyoming Area	71	127	78.9	248	95.3	249.3
P	Northwest	34	50	47.1	642	1,184.0	1,788.2
	Contiguous United States	6,540	12,163	86.0	21,707	78.5	231.9

[1] Includes nuclear as well as conventional thermal plants. Btu requirements for nuclear generation are estimated on the basis of the average heat rate for conventional steam.

[2] Excludes Alaska and Hawaii.

Source: Advisory Committee Report No. 21, prepared by the Fuels Special Technical Advisory Committee, Appendix 1, p. 315, Part II.

Table 21 compares the kilowatt-hours generated from each of the major energy sources in 1963 with estimates for 1980. The actual 1980 figures, and the market shares they imply will, of course, depend on the many hard-to-predict factors which affect interfuel competition. Whatever the precise shares turn out to be, it is clear that each of the fossil fuels will continue to supply both increasing amounts and an important share of a growing market, even though, as the table indicates, the percentage shares of the fossil fuels are expected to decline as a result of important nuclear fuel competition.

Coal, which presently supplies more than half of the market, will continue to be the workhorse for electric generation throughout the survey period, although its percentage share will decline from 54 percent to 47 percent, while natural gas should remain dominant in areas near sources of gas supply, although it can expect increasingly stiff competition elsewhere and on a nationwide basis its share will also decline from the 21 percent of 1963 to 17 percent of 1980. Oil will, in all likelihood, remain confined to coastal areas having access to cheap water transportation, where its share will depend to a large extent on the availability of imports at competitive prices. Overall, it is expected that oil, while more than doubling its volume, will decline on a proportionate basis by a third, from 6 percent to 4 percent of the market. Nuclear fuel will skyrocket from negligible current use to about 19 percent of the 1980 market.

Interfuel Competition

The choice between competing fuels depends not only on delivered prices but on many other factors

TABLE 21

Energy Sources for Generation

	1963		1980	
	Billion kwh	Percent of total	Billion kwh	Percent of total
Coal	494	54	1, 264	47
Natural gas	201	21	458	17
Oil	50	6	107	4
Total fossil fuel	745	81	1, 829	68
Nuclear	3	0. 1	514	19
	748	81	2, 343	87
Water power	166	19	340	13
Total	914	100	2, 683	100

as well, including the relative thermal efficiencies of different fuels and differences in capital costs of generating plants equipped to burn particular fuels. The following statement by the Fuels Committee sums up some additional considerations:

> In determining the type of fuel to be used for electric generation, there are a number of factors to be reviewed and evaluated. Each of these has a bearing on cost and influences the degree to which an electric utility is able to meet its obligation to provide reliable service at a reasonable price. The costs of storing, handling, and in some instances, disposing of the fuel product are economic factors which can make a low-cost fuel the most expensive fuel. In locations where land costs are high and areas heavily congested, these costs become a major consideration in selecting a proper fuel. In some areas, operating conditions, such as air control regulations on the West Coast, may justify a premium fuel. Therefore, while a general picture can be drawn concerning the availability and price of fuels, the final determination in selecting a fuel or fuels for a particular plant must be based on the specific facts pertinent to that plant and its location.[1]

Relative delivered price per Btu is usually the overriding factor in competition among the fossil fuels. The choice of fuel is an integral part of the selection of a plant site but often competition between fuels may occur after a plant is in operation. Many stations are initially designed and equipped to burn alternative fuels interchangeably upon short notice, and stations originally designed for coal can usually be adapted to use gas or oil. Likewise, some gas or oil-burning plants can be adapted to use coal, but unless the plant was originally designed with this in mind, the conversion may be expensive. In many locations the competing positions of alternative fuels are very close, and a price reduction for any one fuel may trigger competitive reductions in other fuel prices.

While the fuel with the lowest delivered cost usually sets the pace for competition, the delivered prices at which fuels become competitive are not always identical. For instance, a coal-burning plant typically requires 10 to 15 percent more capital investment—chiefly in coal and ash handling equipment and more expensive boiler design—than a comparable plant which is not so equipped. However, this differential has a significant effect on interfuel competition only where gas and oil supplies are adequate to serve the plant's entire fuel requirements throughout its service life. Thermal efficiencies, which vary between different grades of the same fuel as well as between different fuels, also affect the relative prices at which fuels are competitive. Coal typically requires some 3 to 5 percent fewer British thermal units per kilowatt-hour than gas, with oil occupying an intermediate position.

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[1] Advisory Committee Report No. 21, p. 317 of Part II.

Interfuel competition is expected to intensify in the future, particularly in the higher fuel cost areas, where improvements in energy transportation and the reductions in the costs of nuclear power should bring fuel costs closer to those of the lower fuel cost areas. Just as nuclear technology is shooting at a continually moving target in attempting to overtake conventional steam-electric generation, nuclear technology in turn is expected to set a continually lowering cost target which the fossil fuels and their modes of transport will be forced to meet.

Coal

Widely varying assessments of coal supplies are available depending upon the purpose and the nature of the investigations. The most recent official Department of the Interior estimate for all types of coal is that "recoverable reserves" in the continental United States, excluding Alaska, amount to 830 billion tons.[2] By comparison the projected energy requirements for thermal electric generation for the year 1980 is equivalent to 900 million tons of coal, of which nearly 500 million tons are expected to be in the form of coal.

The estimates of coal reserves can be misleading. While total reserves are more than adequate to meet any foreseeable demands by the electric utility industry, extensive tracts of coal lands adapted to low-cost mining techniques are by no means unlimited. A better inventory of our low-cost coal reserves than is now available would be of great value in industry planning.

The wide distribution of coal reserves throughout the United States is shown in figure 27 which depicts the "recoverable reserves." It is not generally realized that more coal lies west of the Mississippi River than to the east, although some 60 percent of the higher bituminous grades are found east of the Mississippi. While the western coals can be mined at low cost, they have not been extensively exploited to date, because of their distance from major load centers. Later chapters in the National Power Survey explore the possibilities of utilizing the abundant low-grade coals in the west.

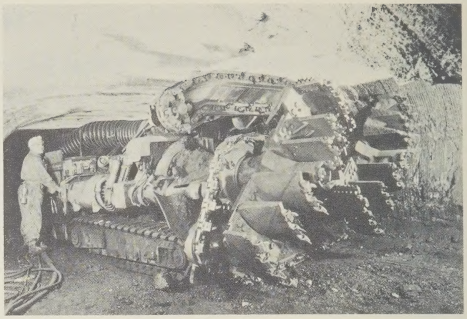

FIGURE 26 *A twin borer continuous mining machine moves between working places in a West Virginia coal mine. These massive and costly machines typify the bituminous coal industry's drive to hold or reduce the price of coal in the face of rising costs. This machine rips coal from the face of the seam and passes it back to the conveyor belt or shuttle cars at a rate of up to 8 tons a minute, eliminating the separate operations of cutting, drilling, blasting and loading.*

Coal costs and prices at the source vary greatly with geologic conditions, methods of mining, required degree of quality control and many other factors. In order to determine the at-source coal prices for large volume utility coal customers, the Fuels Advisory Committee enlisted the cooperation of 20 selected electric systems which purchased over 45 percent of all coal used by electric utilities in 1961. The average price f.o.b. the mine paid by these systems ranged from 12½ cents to 16½ cents per million Btu and averaged 15 cents per million Btu. 1961 prices in the several coal-producing districts are shown in the Advisory Committee's report.[3]

Coal-mining productivity has more than doubled in the past decade from an average of 7.5 tons per man-day in 1952 to 15.4 tons per man-day in 1962, an almost unprecedented productivity improvement for a mature industry. This represents an accelerated rate of improvement over prior years which, if continued, augurs well for the future competitive position of the coal industry. Continued mine mechanization including the use of large shovels such as the one shown in figure 28, more intensive mining machine utilization, improved haulage systems and the development of mines designed specifically to supply the electric power market are factors operating to lower future coal costs at the mine. Mining conditions, changes in wage rates and the costs of competitive fuels can also alter future prices at the mine.

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[2] Advisory Committee Report No. 21, p. 319 of Part II.

[3] Advisory Committee Report No. 21, p. 351 of Part II.

DISTRIBUTION OF FOSSIL FUEL RESERVES

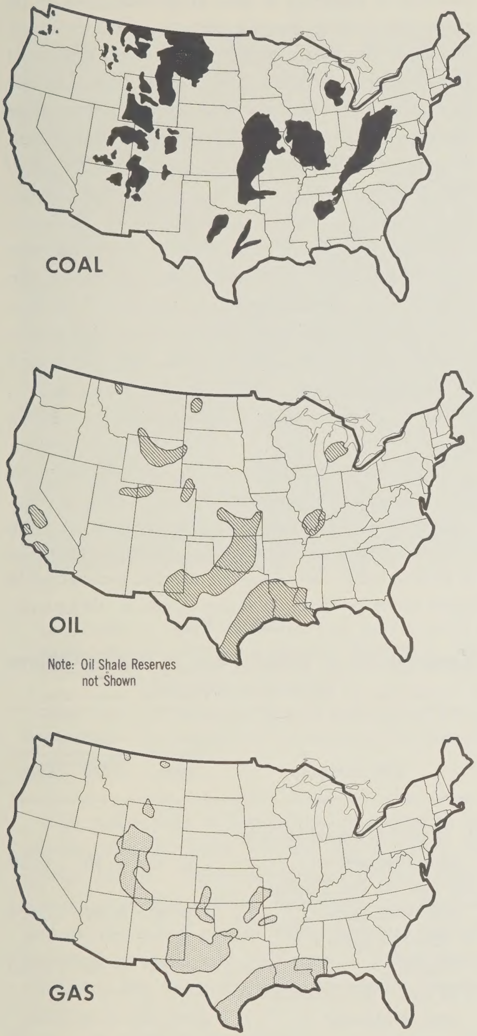

FIGURE 27

In general, the outlook is for stable to moderate reductions in the f.o.b. mine prices with further lowering in delivered costs through broad application of volume movements by highly efficient rail and other transport facilities.

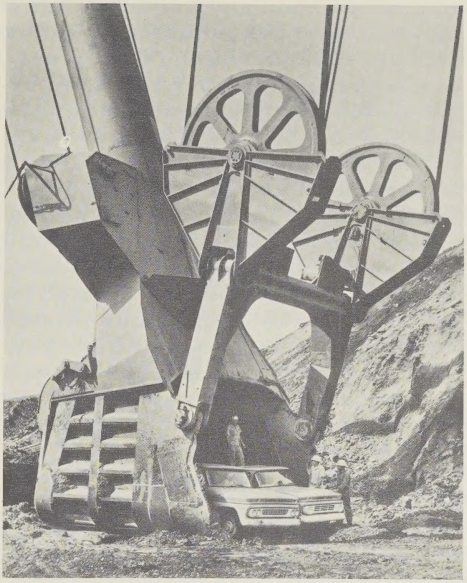

FIGURE 28 *Huge machines, such as this electric powered 115 cubic yard strip shovel, operated by the Peabody Coal Company in its strip mines near Paradise, Kentucky, are contributing to the continued reduction in the cost of mining coal.*

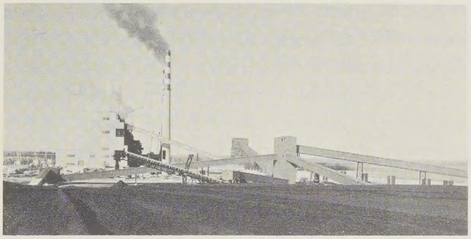

FIGURE 29 *Coal storage yards at coal-burning steam-electric plants contain 4 to 6 months reserve supply of fuel. The stockpile is placed in layers and compacted to prevent spontaneous combustion. The storage yard is equipped with an extensive system of conveyor belts for unloading, stocking and delivering coal to bunkers.*

Natural Gas

Proven recoverable reserves of natural gas in continental United States, excluding Alaska, approximated 276 trillion cubic feet at the beginning of 1964, equivalent to about 11 billion tons of high grade bituminous coal and enough to last about 19 years based on 1963 net production of 14.7 trillion cubic feet. The proven reserve figure, however, is a conservative estimate of the reserves already discovered which can be appraised with a high degree of accuracy, and which are recoverable under current economic and operating conditions. There is no comparable estimate of coal reserves.

Estimates of the additional gas that may ultimately be discovered and produced range from 2 to 10 times the 1964 proven reserves of 276 trillion cubic feet. In addition, we are already importing gas from Canada which has 36.7 trillion cubic feet of proven reserves and there is an immense potential for the discovery of additional gas reserves in that country. Alaska, where exploration has just begun, already has an additional 1.7 trillion cubic feet of proven reserves.

Natural gas reserves are heavily concentrated in five States—Texas, Louisiana, Oklahoma, Kansas, and New Mexico (see fig. 27). This contiguous area accounts for over 88 percent of proven reserves in the continental United States excluding Alaska. While the Geological Survey estimates that most of the United States is favorable for the discovery of natural gas and oil reserves, it is expected that the major portion of new reserves to be found and developed between now and 1980 will be in or near the areas in which reserves have already been found.

Electric utility consumption of natural gas has increased at an average annual rate of 11½ percent during the past three decades. This extraordinary growth reflects the dynamic growth of the natural gas industry, especially since World War II as the extension of natural gas pipelines from the major gas producing areas to every State in the Union other than Maine and Vermont has made natural gas available in many new markets throughout the country. Electric utility purchases, frequently under contracts which provided that service could be interrupted when the pipeline required the gas to serve other customers, contributed to the economic feasibility of pipelines by providing markets in the summer and other periods when residential gas demand is not at its highest and by helping justify the installation of larger and more economical pipelines than would otherwise be needed in advance of growth in residential demand.

During the most recent decade, 1953–63, natural gas consumption for electric generation has increased at an annual rate of approximately 7.5 percent, with the share of total thermal generation supplied by natural gas increasing from 24 to 27 percent during the same period. Large scale extensions of pipelines to new areas continued to be important during the past decade as, for example, in California, where electric utility consumption of natural gas, the local supply being augmented by new pipelines from the Permian and San Juan Basins of Texas and New Mexico, more than tripled. New pipelines were also a factor in the West Central Region (FPC Region VI), the second most important growth area. Another significant factor influencing gas consumption in both areas has been a sharp increase in the share of total generation supplied by fuel burning steam plants and the corresponding decline in the portion of total loads supplied by hydroelectric power. Natúral gas is now available in 46 of the 48 contiguous States, and in 43 of these gas is used to some extent for electric generation.

Table 22 presents projections of future electric utility gas consumption developed by the Commission's Bureau of Natural Gas in cooperation with the Fuels Advisory Committee. The projection of 4 trillion cubic feet of gas for electric generation in

TABLE 22

Consumption of Natural Gas by Electric Utilities

(Trillions of cubic feet)

FPC Regions	Actual 1960	Estimated 1970	Estimated 1980
I, II and III plus Illinois and Wisconsin [1]	0. 33	0. 30	0. 30
IV and VI less Illinois and Wisconsin [2]	0. 20	0. 41	0. 77
V (South Central Region)	0. 81	1. 55	2. 16
VII and VIII (Northwest and Southwest Regions)	0. 39	0. 74	0. 83
Total	1. 73	3. 00	4. 06

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[1] (Northeast, East Central and Southeast Regions plus Illinois and Wisconsin.)

[2] (North Central and West Central Regions less Illinois and Wisconsin.)

1980 is twice the 1962 usage. A detailed account of the basic assumptions and analyses underlying the projections appears in the report of the Fuels Advisory Committee No. 21, p. 315 of Part II.

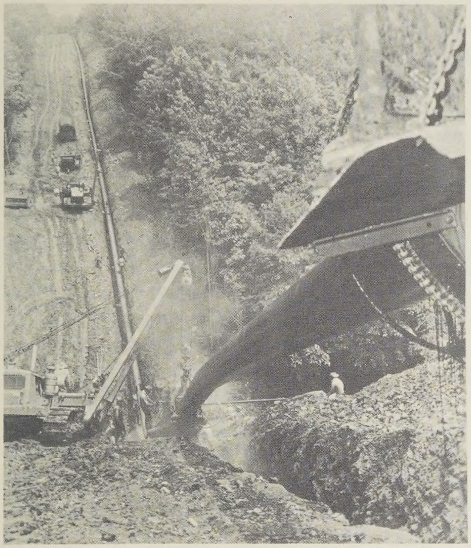

Figure 30 *A link in America's network of major natural gas pipelines is coated and wrapped for extra protection against corrosion before it is placed in the trench. The 190,000-mile network provides the nation with a transport system for the economic supply of natural gas to many areas and for many purposes including its use as primary or interruptible fuel for steam-electric generating stations.*

The projections of future gas consumption by electric utilities, table 22, are based purely on market trends. These projections do not reflect any policy decisions by the Federal Power Commission on the use of gas for boiler fuel and are not intended to imply any prediction of future Commission policy in exercising its regulatory responsibilities in this area.

In table 22 Illinois and Wisconsin are grouped with FPC Regions I, II, and III because they are similar to the other States in those regions in their predominant use of coal as fuel for electric generation. In those areas, it is expected that most of the gas used for future electric generation will be on an interruptible basis. Competition from coal and from nuclear fuels and the expiration of old low-priced gas contracts are likely to prevent a significant net increase in electric utility gas consumption in this section of the country.

Region VI, and the portion of Region IV west of the Mississippi, represent a mixed fuel area with varied competitive situations and generally low delivered gas costs. Gas is projected to maintain its share in this area. The major market for fossil fuels in the Far West (Regions VII and VIII) is in Region VIII which includes California, Arizona, and Nevada, a high fuel cost area in which gas is now the dominant fuel for generation. The projected slowdown in the growth of the boiler fuel market during the 1970's largely reflects the expectation of nuclear competition.

In Region V—the South Central Region—which includes over 90 percent of the Nation's known gas reserves, gas has a substantial competitive edge. However, some load centers are closer to deposits of coal or lignite than to the closest gas fields, and the economic attractiveness of these competitive sources is increasing. The projection for Region V assumes that gas will be the source of 80 percent of the total generation in the region in 1980, and that more than half of total boiler fuel sales of gas will be concentrated in this region.

Interfuel competition, primarily with coal, is expected to limit increases in the cost of natural gas for electric generation to about the present levels in most sections of the country. In the gas producing areas, however, natural gas enjoys a substantial current price advantage with respect to other fuels and thus could increase in price without materially affecting its competitive position. Comparison of the present price of gas in any particular location with limiting prices of competing fuels provides a rough measure of the extent to which the price of gas for power production has room to increase.

Oil

Residual oil, the only fuel oil used in significant quantities for electric generation in the United States, is an oil refinery byproduct which remains after the more valuable refined liquids have been extracted and solids have been removed. Since it is a byproduct, residual oil is supplied in amounts which depend primarily on the market for other refined oil products. Residual is only a small proportion (9.6 percent in 1962) of the total barrels of refined oil products produced domestically, and nearly one-half of U.S. residual oil consumption is supplied by imports. The availability and price of imported residual depends on U.S. import restrictions as well as the world supply and demand for petroleum products.

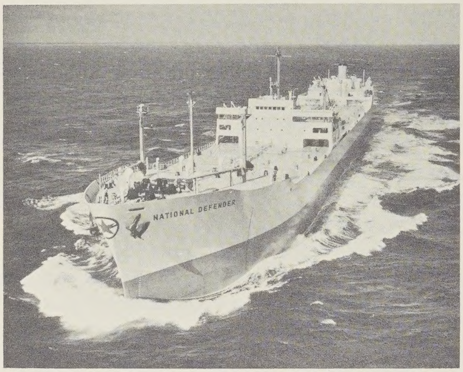

FIGURE 31 *This ship, typical of the modern super-tanker, which carries crude oil to Atlantic Coast ports from southwestern producing areas and crude and residual oil from foreign ports, has a cargo capacity of 66,000 long tons and a draft fully loaded of 42 feet. Refinery residual oil is used extensively as fuel for steam-electric plants along the Atlantic, Gulf and California coasts.*

Residual fuel oil finds its market along the east and west coasts together with some of the areas bordering the major inland waterways. Residual oil can compete with other fuels only where waterborne transport is available. In much of this area, however—especially in the northeastern United States—it provides a competitive influence that would not otherwise exist and thus operates to reduce prices of other fuels to the benefit of the consuming public. Residual oil is purchased by the barrel and a barrel roughly equals one-fourth of 1 ton of coal in heat equivalent. The current average price is approximately $2.10 a barrel, the equivalent of 35 cents per million Btu. In 1962, residual oil was used to produce about 7 percent of total thermal electric generation, but it constituted 27 percent of the fuel used for generation in the Northeast (FPC Statistical Region I).

U.S. import policies are an important factor in the consumption of residual oil by electric utilities as well as other users. A policy of easing import restrictions could be expected to intensify interfuel competition and possibly expand the area within which residual oil competes with other fuels. The effect upon the use of other fuels would depend upon the ability of the various fuels to counter residual's lower price. The overall merits of such a policy depend on complex considerations involving many aspects of the national interest which are beyond the scope of this Survey. The dependence of residual oil availability and price on our international and domestic policies and on world oil markets sets this fuel apart from the other fossil fuels in that it is less amenable to accurate projection based on normal reserve calculations and economic and technological factors. Our projections that residual oil will supply a somewhat smaller share of the market in the future reflect the possibilities of appreciable reductions in the cost of using coal and nuclear energy.

Nuclear

According to the Atomic Energy Commission "reasonably assured resources" of uranium and thorium have a total energy content of more than 94,000 Q [4] but with the existing technology of mining and concentrating nuclear materials only 3/10,000 of this total or 28 Q, could be mined at current cost levels. For comparative purposes, the annual basic energy consumption of the United States (coal, oil, gas and hydro) is about 0.05 Q and recoverable fossil fuel resources are estimated at 15 to 20 Q [5] but may be much higher. Of this amount, perhaps 6 Q is available at current costs.

While the estimate of 28 Q of nuclear fuel represents a very large reserve, the discussion of nuclear fuel resources can be misleading unless we consider the low efficiency with which nuclear fuel is now utilized and the prospects for improving that efficiency. Present reactors utilize nuclear energy with an efficiency of only about one percent of the potential energy in nuclear fuel. As a practical matter no energy is presently realizable from thorium reserves (about 6 Q of the 28 Q). In total, the nuclear energy obtainable with present technology from uranium minable at about current costs thus represents less than one Q rather than 28 Q. While this is only a portion of the ultimate nuclear potential, it is still several times as large as the projected use (at existing efficiencies) of nuclear plants built during the survey period and the technology can be expected to make much larger reserves available during this time. A further discussion of nuclear fuel reserves and the effects of high converter and breeder reactors on more efficient use of these resources is contained in chapter 5.

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[4] A "Q" is a billion billion (10^{18}) Btu, and corresponds to the heat content of about 40 billion tons of high grade coal.

[5] Total recoverable coal reserves for the continental United States excluding Alaska are estimated at 830 billion tons, equivalent to about 16 "Q", but this assumes only 50 percent recovery. Proven oil and gas reserves estimated on a much more conservative basis represent about 1 "Q".

Fuel Transport Cost

Important reductions are being made in the transportation costs of all fossil fuels but the most impressive developments in recent years and in prospect for the near future relate to the transportation of coal. Further, transport costs account for a much larger proportion of the delivered fuel costs for coal than for natural gas and oil. For these reasons the following discussion of transportation costs is largely related to the movement of coal.

Railroad Transport

Coal is the largest single item of railroad traffic. Three-quarters of all coal tonnage shipped in 1962 utilized rail transport for part or all of the movement from mines to consumers. Coal shipments represent close to 40 percent of the freight tonnage and produce about 25 percent of the revenues of Eastern District railroads, which serve the major coal fields east of the Mississippi River.

After World War II, railroad freight rates on coal increased and the total tonnage of coal shipments by rail began to decline. In the late 1950's, the railroads reversed this trend of rate increases and began to adopt low rates for volume movements in an effort to increase tonnage. More recently, the railroad industry, with the approval of regulatory agencies, has adopted still lower "trainload" rates and in cooperation with electric utilities has been exploring new coal transport arrangements to lower costs and effect major reductions in rates for large movements of coal. Increasing competition from barge lines, the perfection of coal pipelines and the emergence of nuclear energy as an added competitor have been major factors spurring railroad action to reduce rates.

An important new development is the "unit" train operating between a single mine and a single generating plant with special equipment and tight scheduling of loading, unloading and movement, and often employing utility owned coal cars. A recent example of such an arrangement is the 126-car shuttle train which in October 1964 will start carrying coal on the Gulf, Mobile and Ohio Railroad from Southwestern Illinois Coal Corp.'s Captain mine located southeast of St. Louis to Commonwealth Edison Co.'s generating station at Joliet, Ill., a distance of about 300 miles. The new rate of $1.30 a ton represents a reduction of 49 percent from the existing rail-barge rate of $2.56. The 100-ton swivel-dump cars will be owned by the utility. (See fig. 32.) Other railroads and utilities have developed equally attractive transportation movements.

On the drawing boards are "integral" trains designed to operate for perhaps a week without refueling. The integral train consists of very large cars permanently coupled to power units interspersed among the cars. The cars are designed for rapid automatic unloading and are insulated and heated to avoid the problem of frozen coal. Integral trains will operate at passenger train speeds with remote control of all features from the head of the train. Train capacity would be about 35,000 tons in contrast to today's big trains of 7,000 to 10,000 tons. A control car at each end of the train would permit shuttle service without the necessity for turning at either end of the run. A key factor in the integral train's economy is its short "turn around time" from loading at mine to unloading at power plant and return, with major savings in the fixed charge component of cost.

The availability of sharply reduced freight rates for large volume movements of coal to steam generating plants has added a new and very large additional element of savings realizable in providing generating capacity in large units and stations. Larger generating units are more efficient and less costly per kilowatt in themselves. But the savings in coal transportation rates from the volume movements they make possible provide additional savings which are perhaps just as large or in some cases even larger than the savings in the cost of generation.

Volume movements and improved techniques of coal transportation can be expected to permit substantial reductions in railroad rates for coal by 1980. Figure 33, based on the study by the Fuels Com-

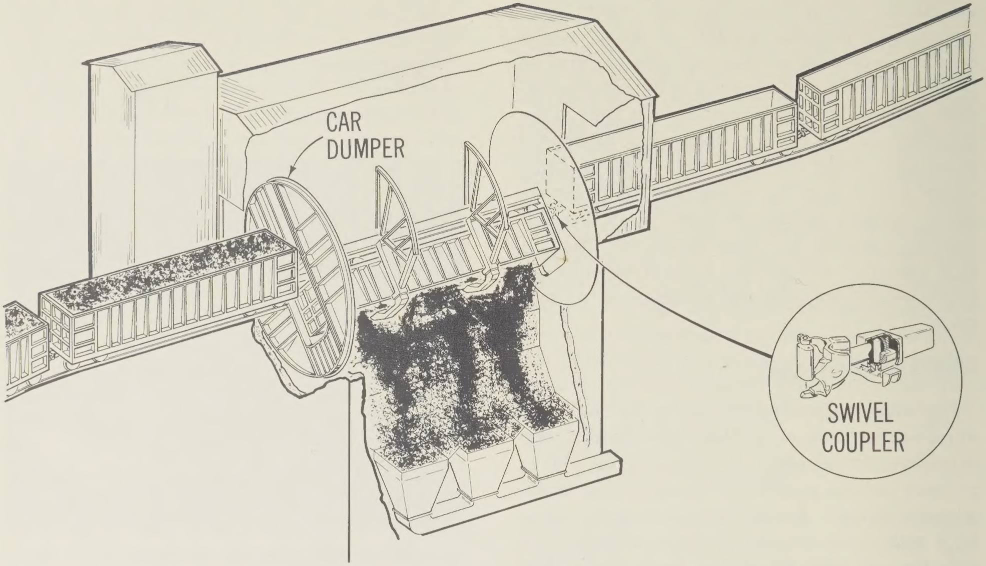


FIGURE 32 *Unit Train of the Commonwealth Edison Company is typical of newly developed specialized trains which can move coal from the mine to large power stations at greatly reduced costs because of simplified operations and shortened round-trip elapsed time. Each of these trains can carry in the order of 12,000 tons of coal.*

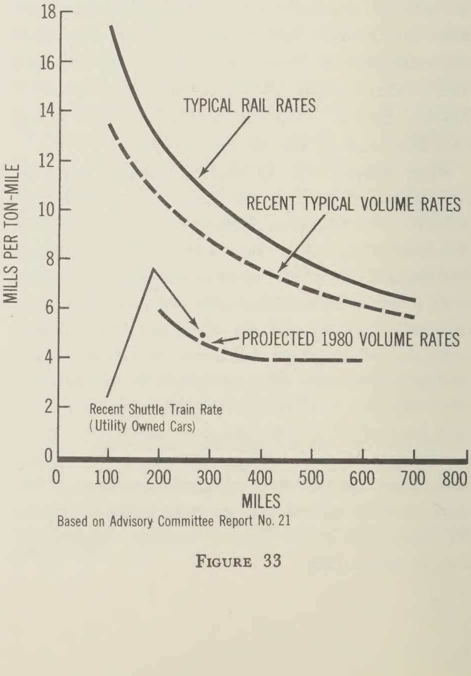
mittee, compares 1963 rates with the Committee's 1980 projection, and shows the large reductions in rail rates already in effect on volume movements of coal and the even greater reductions expected by 1980. With a high degree of automation even lower costs may be possible during the Survey period.

Pipeline Transport

The technology of pipeline transport for oil and natural gas is well developed and highly efficient. Some improvement in economy is possible in the future with the use of pipe of larger diameter and of greater strength to permit higher pumping pressures.

A new development which has excited much interest is the movement of coal in slurry form by pipeline. The successful operation of a 108-mile-long coal-slurry pipeline in the 6-year period 1957–63 has demonstrated the economic and technical feasibility of this method of coal transport. (See fig. 34.)

RATES FOR COAL SHIPMENT BY RAILROAD



Based on Advisory Committee Report No. 21

FIGURE 33

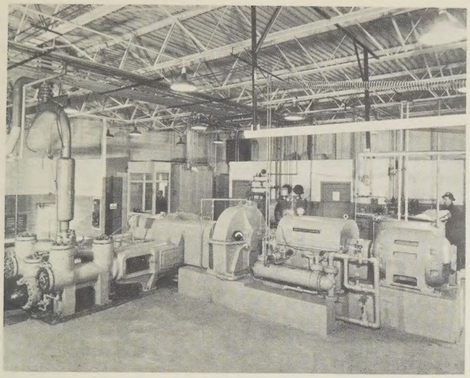


FIGURE 34 *View on one of the three pumping stations on Consolidated Coal Company's 108-mile, 10-inch, coal slurry pipeline from Cadiz, Ohio to Cleveland, Ohio. The line operated successfully from 1958 to 1963, delivering 1.25 million tons of coal per year.*

The Fuels Advisory Committee, in Advisory Committee Report No. 21, discussed in detail the considerations affecting a utility's choice of a coal pipeline *vis a vis* other modes of coal transport and summarized its findings as follows:

> After moving over 700 million ton miles of coal, cross-country shipment of fine coal has been amply demonstrated on Consolidation Coal Co.'s pipeline from Cadiz to Eastlake, Ohio. A successful demonstration of direct firing of coal slurry in a cyclone burner furnace has been conducted at the Werner Station in South Amboy, N.J. Tests at Eastlake, Ohio, have demonstrated the use of filter-pulverizer and centrifuge pulverizer system to dewater slurry to 22 percent and 18 percent moisture content for firing in pulverizer-furnace burner. It is apparent that large volume delivery of coal slurry by pipeline to centers of heavy electric generation are practical and can compete with alternate methods of transportation. Pipelines can be designed to handle lower grade coals. Use of slurry will result in additional savings at new power plants because a great deal of conventional coal handling facilities can be eliminated. Storage of inventory is a problem that has not been optimized but it does not represent any obstacle. Tests and demonstrations indicate that coal slurry can be used for cyclone as well as pulverized coal burners. Since pipelines are installed underground, there does not appear to be a major public relations problem in their construction. Once a line is constructed, because of the relationship between variable and fixed costs, the transportation component of cost should remain very stable. This protects against inflationary factors but deprives the user of future technological cost reductions which may be realized by other methods of coal transport. At present, there are legal problems in obtaining right-of-way. Every effort should be made to eliminate these legal problems so that pipelines can compete on merit.
>
> In the construction of large electric generating plants of the future, transportation of coal by pipeline must be given full and careful consideration.

Water Transport

Water transport by inland barge or ocean vessel is often the lowest cost mode of transport for oil or coal. The possibilities of transporting liquified natural gas (at a temperature below minus 116 degrees Fahrenheit) are being explored and the technical feasibility of this form of transportation has already been demonstrated for ocean movements. However no movements of liquified gas have so far been introduced in the United States.

Costs of transshipment tend to limit the availability of water transport to fuel sources near waterways and to generating stations which can be served directly by water. The waterway developments along the Mississippi, Ohio, and Tennessee River systems, the Great Lakes, and at coastal points provide many locations which can be served by the water carriers. (See fig. 35.)

A key element affecting the costs of water transport is the limitations which the physical characteristics of our waterways impose upon the barge or vessel. For example, the sizes of individual barges

FIGURE 35 *Slack water barge navigation on the Nation's network of developed waterways economically moves large tonnages of coal to dock-side power plants.*

and groups of barges or "tows" (propelled by a single tow-boat) are controlled by the size of the locks and depth of the navigable channels. The outlook for lower rates on shipments by barge on the inland waterways is therefore limited by the physical characteristics of the waterways which do not lend themselves to ready expansion of tow sizes and quick turn-around equipment. However, increased tonnage on our waterways, larger locks, and stiffer competition from the railroads are factors which suggest that lower rates may be in the offing. Reductions in coastal coal and oil transport rates through use of special barges and tugs are also possible.

Transmission of Electric Energy

An alternative to the transport of fuels from their sources to electric generating stations is the transmission of electric energy at high voltage from generating stations located near the fuel sources. It will suffice here merely to point out this alternative. The technical and economic considerations affecting this choice are discussed in chapters 9 and 10. Indications of the manner in which this alternative is likely to develop during the next two decades are given in chapter 15.

Comparison of Delivered Energy Costs

Table 23 presents, region-by-region as well as for the Nation as a whole, the average cost of fossil fuels delivered to electric generating plants in 1962 and an estimate for 1980. The estimates for 1980 reflect the influence of such factors as an increasing proportion of mine-mouth as opposed to load center generation as well as anticipated improvements in the cost of mining and transport of fuels.

TABLE 23

Average Delivered Cost of Fossil Fuel Cents per Million Btu

FPC Statistical Regions	1962 [1]	1980 [2]
I. Northeast	31	25
II. East Central	25	18
III. Southeast	24	21
IV. North Central	26	20
V. South Central	20	20
VI. West Central	26	18
VII. Northwest	23	23
VIII. Southwest	34	30
National average (excluding Alaska and Hawaii)	26	21

[1] Based on FPC and EEI data.

[2] FPC Estimate.

Conclusions

It is impossible to predict the combined effect of the considerations discussed in this chapter with respect to each fuel and each mode of fuel transport, including the alternative of electric power transmission. Nevertheless, as table 23 indicates, it would appear that we can expect a downward trend in the delivered cost of fuel in most locations.

CHAPTER 4

CONVENTIONAL STEAM-ELECTRIC GENERATION

Conventional steam-electric generation is the source of four out of five kilowatt-hours of electric energy produced in the United States today. From the beginning of the electric power industry in 1882, it has been one of the two principal sources of energy supply. In the first three decades of the industry, steam-electric power shared the load about equally with hydroelectric power but the proportion of steam power rose to 70 percent of total generation by 1920 and then gradually increased to its present position of over 80 percent. By 1980 steam electric generation is expected to account for 87 percent of total production, with 68 percent by conventional fossil fired steam plants and 19 percent from nuclear powered steam plants (discussed separately in chapter 5). Hydroelectric power will supply the remaining 13 percent.

Continuous technological progress has steadily improved the efficiency, availability, and reliability of the steam-electric process. Good fossil fuel deposits abound in many regions of the country and their products are available for use in economic mine-mouth plants or transportation to plants at the major load centers at competitive costs. Because the steam power plant is not dependent on rainfall and water availability in the sense that the hydro plant is, it can supply power during all seasons of the year. Steam-electric units can be designed to burn several kinds of fossil fuels and to change from one fuel to another on short notice to take advantage of the cheapest fuel available.

History of Steam-Electric Power

The history of steam-electric power is one of continuous growth of demands for electric power and an unfailing advance in the art of boiler and turbine-generator design and combustion of fuels. This progress has been made possible by developments in high-temperature metallurgy, in the techniques of metal fabrication and in instrumentation. Decade after decade steam power units have increased in size and the amount of fuel required to generate a kilowatt-hour of electric energy has decreased. Continuing improvements in plant operating techniques have been important in reducing costs.

To World War II

Until about 1900 the only prime mover available to the industry was the slow speed Corliss steam engine which was limited to ratings of less than 2,500 horsepower. The introduction of the steam turbine broke the prime-mover bottleneck by permitting much larger concentrations of capacity in a single unit. The increase in sizes of turbines however, was not immediately accompanied by an increase in the size of boilers. At first a battery of several boilers was necessary to supply the steam required for one turbine, but major improvements followed in boiler design. Today's modern plants commonly have unit boiler-turbine-generator combinations.

The continuing demand for more steam to drive larger turbine-generators led to major technical changes in the design of boilers. Among the many changes in boiler design were the introduction of automatic combustion controls, replacement of the rivet by the electric weld in steam drum construction, the change from grate burning of coal to suspension burning in a pulverized state, the development of the water-cooled walls, advances in boiler water chemistry, development of high-temperature alloy steels, the cyclone furnace, the development of the supercritical cycle and with it the once-through circulation concept and as mentioned above, the development of the single boiler-single turbine concept. These developments enabled the industry to increase steaming capacity of the boiler and to increase the temperature and pressure of steam available at the turbine throttle, which in turn led to larger turbine-generators and overall improvements in plant design. In the turbines the advances included longer blades and higher efficiencies and in the generators, increases in capacity in relation to generator size through hydrogen cooling and, more recently, oil and water cooling.

By 1940 the most advanced steam-electric installation was using steam at 900° F. and 2,300

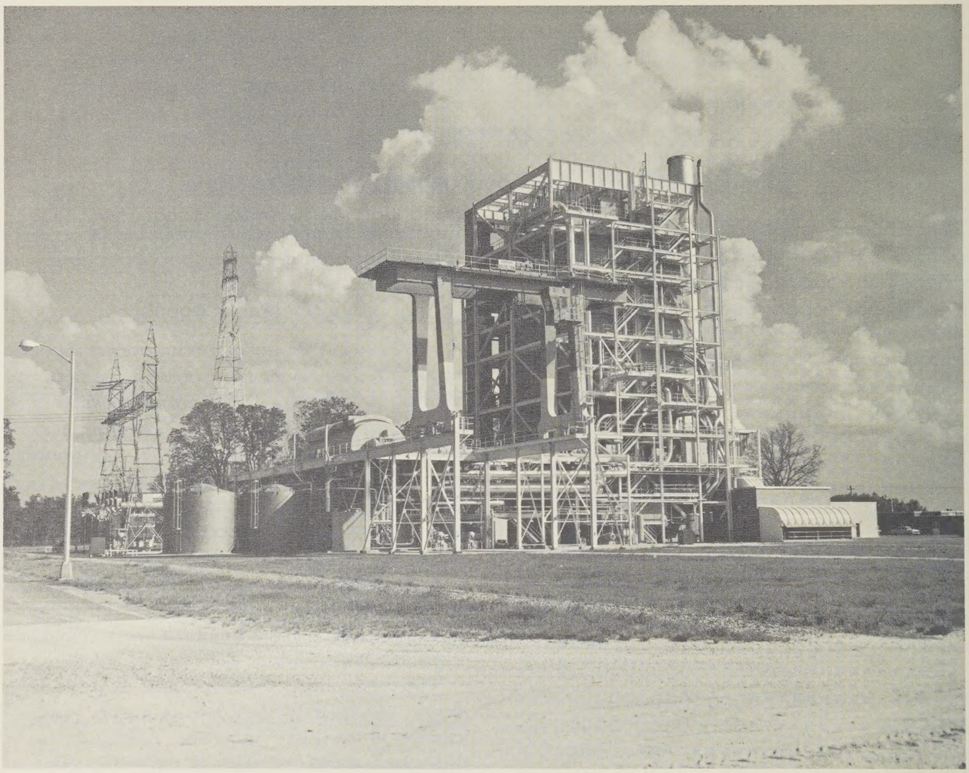


FIGURE 36 *The 247,000 kw Little Gypsy station of the Louisiana Power Company, completed in 1961, demonstrates improved economy through unitized boiler-generator concept of design, natural gas firing and outdoor type of station construction.*

psi[1] with reheat to 940° F. Except for one 200 megawatt unit, the large units were in the range of 125 megawatts. Power plant equipment including boilers, auxiliaries and controls reached a degree of reliability which make it practicable to employ "unit-type" construction, i.e. one boiler per turbine-generator thereby eliminating standby boiler equipment.

The thermal efficiency of steam-electric generation which was as low as 5 percent in 1900 increased to 30 percent in 1940. In terms of the coal requirements, this achievement represented a reduction in coal consumption required to generate a kilowatt-hour of electricity from 6 pounds to less than 1 pound of 12,500 Btu coal.

Postwar Improvements

Following World War II, the utility industry was faced with a challenging situation calling for an accelerated application of the developments first introduced in the prewar years. An inflationary trend in the economy had made improvements in conventional steam-electric generation imperative. At the same time, continuing growth of electric loads created ample opportunity for perfecting and using new ideas in the design of each addition to system capacity. The release from war-time controls and restrictions was another factor influencing new developments.

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[1] Pounds per square inch.

After 1946, two general trends developed. One was a rapid increase in unit size to reduce capital and operating costs of steam-electric power plants. The other was a bolder extrapolation of industry experience with higher temperatures and pressures to attain greater thermal efficiencies. Increases in unit sizes and pressures and temperatures are and have been interrelated as was pointed out in Advisory Committee Report No. 7.[2] The prewar practice of advancing steam temperatures and pressures only after the industry had acquired an adequate fund of knowledge and experience gave way. New and larger units employing higher temperatures and pressures were ordered even before the lessons could be learned from the previous advances.

This accelerated advance into larger sizes and higher steam conditions has resulted in substantially lower unit costs despite some increase in the amount of time that pioneer units of the new larger sizes have been out of service. In spite of rising cost of materials and labor, the average kilowatt-hour production cost of steam power has been more or less stabilized and since 1958 has been decreasing.

The development of larger unit sizes and higher steam pressures and temperatures has triggered other significant improvements in steam power plants. Among these are basic changes in the design of plant structures, the layout of plant equipment, the simplification of coal handling, and the centralization of plant controls. In place of traditional brick and ornamented buildings to house equipment, less costly structures and even semi-outdoor and outdoor designs were used. Duplicate equipment was eliminated where possible, and the simplified unit-type construction referred to above was almost universally adopted.

A more recent development is the trend to use computers to control plant operations. The problems are more difficult in the case of coal-fired plants and are not yet fully solved. However, it is expected that within a few years, computers will be able to start-up and shut-down large steam-electric units without the intervention of an operator. Full automation should improve the safety of operations and reduce fuel and maintenance costs of the large expensive units while improving their service availability.

Trend in Unit Sizes and Temperatures and Pressures

The record of the industry's achievement since World War II is dramatically reflected in the rapid increase in the sizes of units purchased each year. This is illustrated in figures 39 and 40. The largest boiler on order in 1964, a twin-furnace type, has a generating capacity of over 6.5 million pounds of steam per hour. It represents a threefold increase over the capacity of the largest boiler ordered in 1955. During the same period there was a twofold increase in the average capacity of boilers added to power systems. The size of turbine-generators has followed the same trend as that of boilers.

The average steam temperature in 1946 was 800° F. and the maximum was 1,000° F. Today

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[2] Advisory Committee Report No. 7, p. 51 and table 1, p. 52 of Part II.

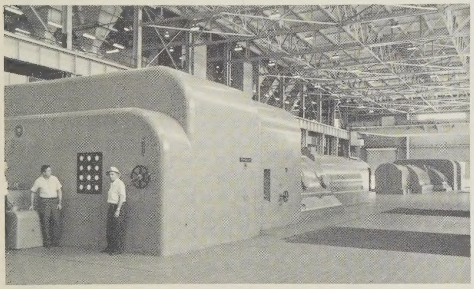


FIGURE 37 *This view in the Thomas H. Allen power plant, built by the City of Memphis shows two of the plant's three 250,000 kw turbine-generators. The units operate at 2400 pounds per square inch and 1050°F/1050°F reheat. The unit boilers have cyclone furnaces and use either coal or natural gas.*

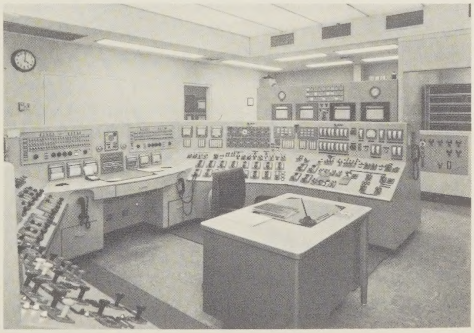


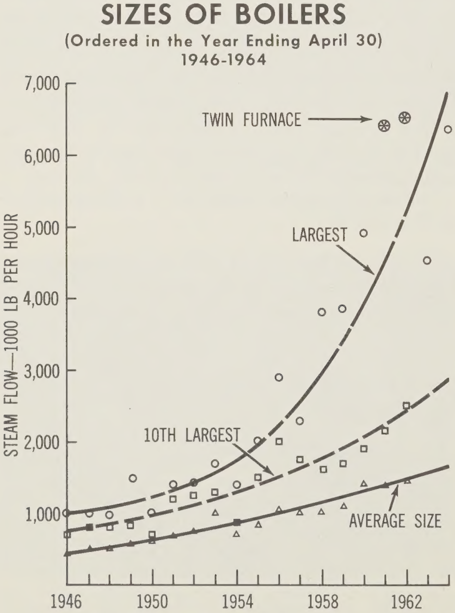
FIGURE 38 *Centralization of boiler and turbine generator controls results in improved economy and station performance at the Huntington station of the Southern California Edison Company.*

both the average and the maximum steam temperatures for large units have risen 200° F.—to 1,000° F. and 1,200° F. respectively. However, 1,000° or 1,050° F. (at 3,500 psi) is considered a practical limit by most designers at the present time. The average throttle pressure in 1946 was less than 900 psi and the maximum was 2,300 psi. Today the average is nearly 1,800 psi and, in a single case, the maximum has reached 5,000 psi. However, the 3,500 psi is considered as today's upper limit of economical operating pressure.

Trends in Heat Rates

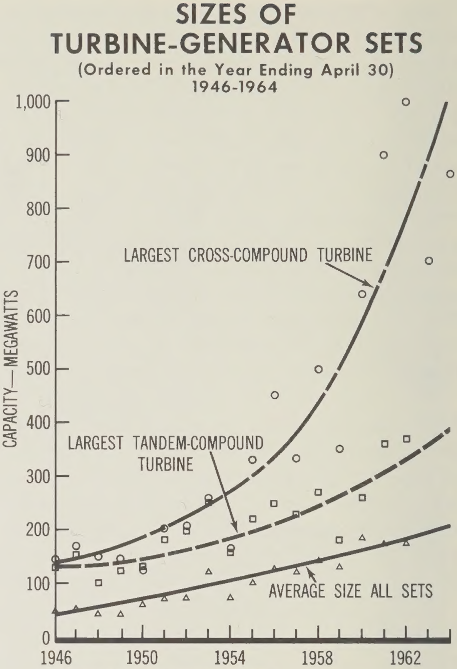
These increases in unit sizes, temperatures and pressures, accompanied by improvements in equipment design, have been responsible for a continuing reduction in the net station heat rate (the amount of fuel required to generate 1 kilowatt-hour).

Table 24 illustrates this trend in terms of the most efficient plant for the period of record, 1925 to date. It also shows the decreasing national average heat rate for the same period, and the best system performance from 1950 to the present time.



Based on Advisory Committee Report No. 7

FIGURE 39



Based on Advisory Committee Report No. 7

FIGURE 40

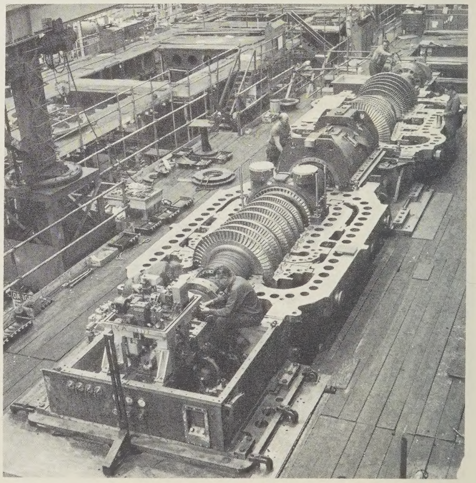


FIGURE 41 *View shows partially assembled high pressure element of a steam turbine for a 900,000 kilowatt cross-compound steam turbine-generator.*

TABLE 24

Net Heat Rates for Steam-Electric Generating Stations 1925 to 1962

Year	Best plant[2] Btu/kwh	Best system Btu/kwh	U.S.[1] average Btu/kwh
1925.........	15,000	[3] NA	25,000
1930.........	12,900	NA	19,800
1935.........	12,300	NA	17,850
1936.........	10,954	NA	17,800
1937.........	10,779	NA	17,850
1938.........	10,788	NA	17,450
1939.........	10,770	NA	16,700
1940.........	10,729	NA	16,400
1941.........	10,606	NA	16,550
1942.........	10,596	NA	16,100
1943.........	11,021	NA	16,000
1944.........	10,689	NA	15,850
1945.........	10,345	NA	15,800
1946.........	10,608	12,715	15,700
1947.........	10,600	NA	15,600
1948.........	10,588	NA	15,738
1949.........	10,437	NA	15,033
1950.........	9,378	11,876	14,030
1951.........	9,379	11,676	13,641
1952.........	9,303	11,665	13.361
1953.........	9,329	11,185	12,889
1954.........	9,113	10,660	12,180
1955.........	9,151	10,270	11,699
1956.........	9,106	9,780	11,456
1957.........	9,118	9,705	11,365
1958.........	9,130	9,760	11,085
1959.........	9,011	9,620	10,970
1960.........	8,975	9,590	10,760
1961.........	8,760	9,363	10,650
1962.........	8,588	9,390	10,558

[1] Exclusive of Alaska and Hawaii.
[2] Plants in service full year.
[3] NA—Not available.

During the 38 years, 1925 to 1962 inclusive, the "best plant" heat rate improved from 15,000 to 8,588 Btu, an improvement of 43 percent, nearly two-thirds of which was accomplished in the 15 years from 1925 to 1940. The later years show a much more gradual decline illustrating the decreasing opportunities for significant improvements in the conventional steam-electric cycle.

The improvement in the "U.S. average" heat rate for the same period was almost 58 percent ranging from 25,000 Btu in 1925 to 10,558 in 1962. These figures indicate the great savings in fuel resources achieved through improved plant design. The spread between the best plant, the best system, and the U.S. national average suggests that large opportunities for further improvements in the U.S. average remain although the spread has become noticeably smaller over the years.

The future annual heat rate gains for the best plant will be quite small for some time because supercritical pressures of 3,500 to 5,000 psi and temperatures of 1,100° to 1,200° F. are reflected in the data for 1961 and 1962. New steam cycles or combined cycles involving some of the new methods of thermal generation discussed in chapter 8, will be required for further substantial gains.

Trends in Production Costs

In spite of the general increase in construction costs and wage rates, steam-electric plants were able to maintain remarkable stability in production costs during the postwar years. This was due not only to the steadily decreasing system heat rates, but also to major advancements in coal mining methods which enabled the coal industry to hold down the price of coal. The average total production cost of conventional steam-electric power produced by the privately-owned class A and B utilities for the years 1940 to 1962 is shown in figure 42. In 1962 this average cost was slightly over 7.5 mills per kilowatt-hour. The more economical of the privately-owned steam-electric plants in 1964 are producing high load factor power at 5 mills or less per kilowatt-hour.

The downward trend in steam power production costs during recent years is also indicated by table 25 which is based on a study of the annual production expenses (excluding fixed charges) of 500 selected steam-electric plants.[3] Declining heat rates are largely responsible for the lowering of fuel costs during the 5-year period.

Opportunities for Further Improvement

There is reason to expect further improvement in all of the elements that together have produced the best plants of today with their outstanding records of reducing the cost of conventional steam-electric power.

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[3] FPC *Steam-Electric Plant Construction Cost and Annual Production Expenses—1961.*

TABLE 25

Steam Power Production Expenses

	1957	1958	1959	1960	1961	1962
Mills per kwh:						
Fuel	3. 02	2. 94	2. 82	2. 81	2. 78	2. 75
Operation and maintenance	. 88	. 91	. 85	. 85	. 81	. 79
Total	3. 90	3. 85	3. 67	3. 66	3. 59	3. 54

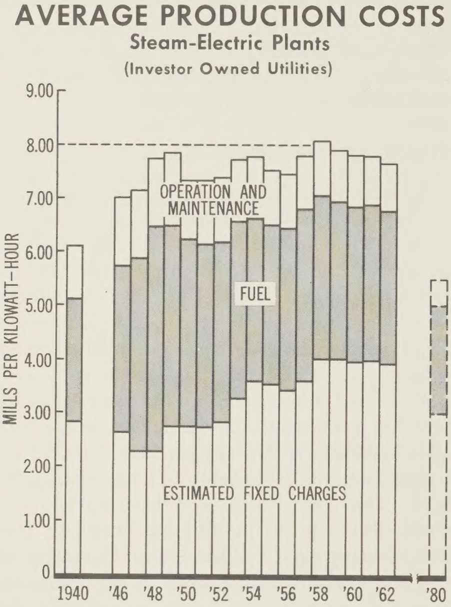

FIGURE 42

Aside from the recent reductions in the delivered cost of fuel, which are discussed in the preceding chapter, savings in the base-load operations of plants stem from (1) reduced annual operating and maintenance expenses, (2) lower investment cost per kilowatt of capacity and (3) improved heat rate. The first category, operating and maintenance expenses, as the preceding chart shows, is rather small when compared with the other two cost components. Yet they deserve appropriate consideration.

Lower investment cost per kilowatt of capacity has been attained by increasing the unit size and getting more capacity in a casing as well as on a shaft. Some further gains are considered possible by going to still larger units with the optimum steam conditions applicable to a given size and location. (See fig. 45.)

The total investment cost of a typical, modern, multiple unit coal-burning plant, exclusive of land, may be divided functionally, very roughly as follows:

TABLE 26

	Percent
Plant building, structures and yard improvements	15
Boiler plant including coal and ash handling, feedwater system, piping and auxiliaries	43
Turbine-generator including condenser system	32
Accessory electric equipment	8
Miscellaneous shop, laboratory, office, equipment, etc	2
Total	100

For a plant designed to burn natural gas or oil only, the absence of coal and ash-handling facilities results in substantial savings as hereafter discussed.

Obviously, the boiler plant and the turbine-generator, representing some 75 percent of the total cost, afford the largest areas for cost betterment. However, all items deserve close study.

Before considering these two major items it is well to consider the possibilities of further simplification of overall plant design and the possibility of taking full advantage of a functional "kilowatt-hour factory" concept. This means, for example, continuing simplification of plant buildings by substituting lower cost materials and construction practices. Advisory Committee Report No. 7 (p. 53 of

Part II) mentions engineering, design, instrumentation and controls as cost items, not directly size-related, the cost of which should tend, on a per kilowatt basis, to decrease as unit size is increased.

The very substantial savings in per kilowatt investment cost in going from the small units, under 100 megawatts, to unit sizes of 300 to 500 megawatts during the past decade is a matter of record. Advisory Committee Report No. 7 (p. 53 of Part II) indicates that in going from a 500 megawatt to a 1,000 megawatt unit, there may be savings of $8 to $10 per kilowatt. The savings in going from the 1,000 megawatt to the 1,500 megawatt unit are expected to be less, but $3 to $6 per kilowatt should be attainable. Since the first 1,000-megawatt unit is still under construction, there is no real experience with such units. However, Report No. 7 (p. 57 of Part II) notes that 1,500-megawatt units probably will be in service by 1980.

The highest economically justified steam conditions today are 3,500 psi and 1,000° or 1,050° F. with double reheat, for units of 350 megawatts and larger. In some recent specific cases these conditions have not been economically justifiable. By 1980 or even earlier pressures of 5,000 psi or slightly higher and temperatures of 1,200° F. may be justified in specific cases for large units in high fuel cost areas but the gains in heat rate for conventional steam cycles taper off rather sharply in advancing beyond 3,500 psi and 1,050° F.

Metals are available today with properties satisfactory for use in steam-electric generating units at 1,100° to 1,200° F. and 5,000 psi, but their life is limited and their costs are so high that they cannot be justified economically at this time. However, with the experience presently being gained and with new research, within the next decade, the price of needed metals may be reduced to an acceptable level.

A promising prospect for further heat rate improvement may be in the dual or combined cycle generating unit. In one version, a gas- or oil-fired gas turbine unit is operated in conjunction with a conventional gas-fired steam turbine generator unit. The gas turbine exhaust which contains large amounts of unburned oxygen is utilized as preheated combustion air for the conventional, pressurized steam boiler. The first such relatively large unit, 245 megawatts, was placed in service in Oklahoma City in June 1963. The expected overall gain in thermal efficiency is about four percent, which is worth considering. Such combined cycle units in still larger sizes should have a definite place in the gas producing areas.

The potentialities for the development of dual purpose plants to produce electric power and byproduct steam for industrial use (including desalting of sea water) on an economical, commercial scale should not be overlooked in planning for the future.

The byproduct plants would be generally similar to the 500 megawatt Bergen plant at the Public Service Electric & Gas Co. which supplies steam to a large oil refinery and the 300 megawatt Deepwater plant of the Atlantic City Electric Co. which furnishes steam for chemical processing. There are also several considerably smaller plants throughout the country supplying steam to oil refineries, chemical plants, and the meat processing industry.

Research work to date on a generally similar installation utilizing coal instead of gas to fuel the "gas" turbine has not yet resulted in a practical, economical unit. But continued research and development may result in a successful coal turbine.

Cost Trends in Power Production

Trends in steam-electric power costs are shown in figure 45, "Performance and Cost Character-

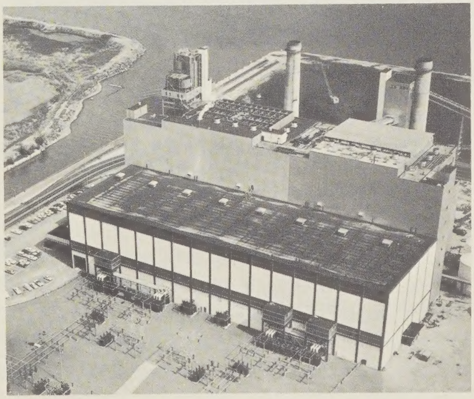

FIGURE 43 *The Eddystone generating station of the Philadelphia Electric Company, a two-unit 726,000 kilowatt plant, leads in lowest heat rate—8,588 Btu per net kilowatt-hour accomplished in 1962. The 5,000 pound per square inch pressure and 1200°F maximum temperature of Unit No. 1 is the highest of any plant in operation.*

istics," which illustrates graphically the economies of size. All curves shown assume optimum steam conditions for the given size.

As the upper curve of investment costs per kilowatt shows, a decrease in cost per kilowatt of approximately 37 percent is realized in going from a plant with two 100-megawatt units to a plant with two 600-megawatt units. A further decrease of 12 percent is expected in going from two 600-megawatt units to two 1,600-megawatt units.

The middle curve shows gains of approximately 13 percent and 3 percent in thermal efficiency for the two size ranges cited. Finally, the bottom curve shows for the same cases savings of 57 percent and 38 percent in the annual operation and maintenance expense per kilowatt.

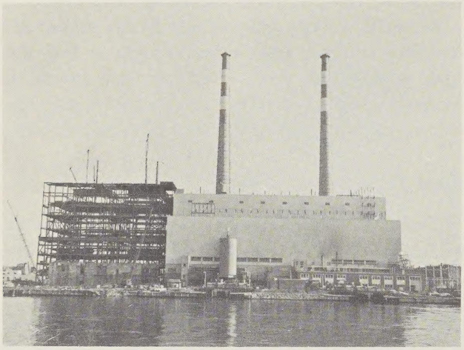

Figure 44 *The Ravenswood Generation Station of the Consolidated Edison Company of New York is being enlarged to include a third unit with a capability of one million kw, the first unit of this size to be built. The total capability of units 1 and 2 is 832,000 kilowatts.*

Table 27, which compares annual costs between a 3,200-megawatt, two-unit plant, and eight 400-megawatt, two-unit plants that would produce the same amount of energy annually, summarizes the economic relationships suggested by figure 45. It also indicates the approximate relative weight of each of the three major cost components making up the total cost of producing steam-electric power.

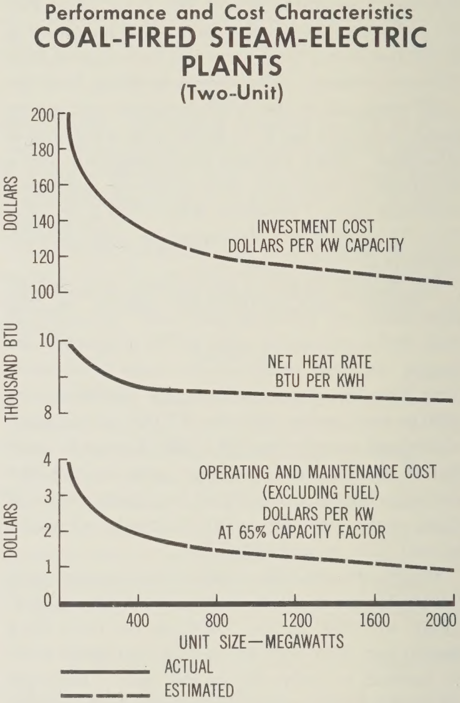

Figure 45

TABLE 27

Estimated Power Production Costs

	1–3,200 mw plant		8–400 mw plants		Savings	
	$1,000/yr.	Mills/kwh	$1,000/yr.	Mills/kwh	$1,000/yr.	Mills/kwh
Fixed charges	$47,520	2.61	$66,528	3.65	$19,008	1.04
Fuel expenses	24,490	1.34	26,824	1.47	2,334	0.13
Operation and maintenance expenses	3,300	0.18	7,760	0.43	4,460	0.25
Total	75,310	4.13	101,112	5.55	25,802	1.42

Note.—Assumes in each case, production of 18.2 billion kwh a year which is equivalent to an annual capacity factor of 65 percent.

The same annual fixed charge rates, delivered fuel costs, and annual capacity factors were used in the comparison.

The estimated savings in favor of the one large two-unit plant are almost $26 million or 26 percent under the small plant costs. However, somewhat larger generating reserves would be required for the larger units. Comparable savings can be shown in the case of gas- or oil-fired plants. Cost variations for such plants are discussed in the following section.

Cost Variations Related to Alternative Fuels

The cost of building a coal-fired plant as well as the annual operations and maintenance expense are larger than the corresponding cost and expense of a plant designed to burn only oil or gas. The additional investment in coal and ash handling equipment and the difference in design of a coal-fired boiler cost between $15 and $30 per kilowatt more than for an all-gas installation—a very substantial item. The construction cost of a basic oil-fired plant lies between that of a straight-gas-fired plant and that of a coal-fired plant, being somewhat closer to the former. Facilities for oil storage and handling cost much less than those for coal, but there are very few large plants of the straight oil-fired type.

In addition to the higher investment cost of a coal-fired station, the coal and ash handling facilities require additional operating personnel, and the added maintenance costs attributable to coal-burning facilities account for higher annual operating costs for the coal-fired plant than those of the straight gas or oil-fired plant.

On the other hand, the coal-burning plant has a heat rate advantage over the oil- or gas-fired plant. Inherently coal is the most efficient of the three fuels and a good grade of coal properly fired will produce more useful heat energy than an equivalent Btu amount of gas or oil fuel. This results from the fact that combustion of any fuel rich in hydrogen, such as oil or gas, produces significant amounts of water vapor, the latent heat of vaporization being lost in the gases passing up the stack.

As a matter of fact, the large modern cyclone or pulverized coal boilers can also burn gas or oil for a very small additional investment in burner equipment. Consequently outside the large gas and coal producing areas these boilers are often designed so that all three of the fuels can be burned as dictated by availability and delivered cost. Many such boilers in the course of a year will burn all three fuels when and if available on a competitive basis.

Considerations in Location of Large Generating Stations

One of the most challenging problems which repeatedly faces each principal electric utility is that of deciding where to locate the next large generating station so as to provide the desired increment of power supply at the lowest cost. Such a decision is usually based on a series of engineering and economic studies of a number of available sites. Important factors considered in such studies include fuel supply, distribution of load, load growth, existing and prospective patterns of loading of the transmission system, interconnections with other systems, availability of land, foundation conditions, availability of cooling water, growing concern for thermal pollution by fish and wildlife groups and agencies, and air pollution problems.

Availability of Good Sites

The number of good sites available for large generating stations is decreasing with the increase in population, expansion of the economy, and the more active interest of the general public as well as the state and local public agencies in community matters, and thermal and air pollution. It is in the best interests of the electric utilities and their customers to use each site selected for the largest generating plant that can be economically justified.

Cooling Water Requirements

For many years, most steam-electric generating stations have been located along rivers, lakes, and tidewaters because of the need of an adequate supply of water to condense the steam leaving the turbines. Water is pumped through the condenser to absorb the heat given up by the condensing steam. The amount of cooling water required depends upon the size of the plant, its efficiency or heat rate, and the permissible temperature rise of the cooling water passing through the condenser. For example, for a temperature rise of 13° F., a flow of condenser water of about 1.5 cubic feet per second, or

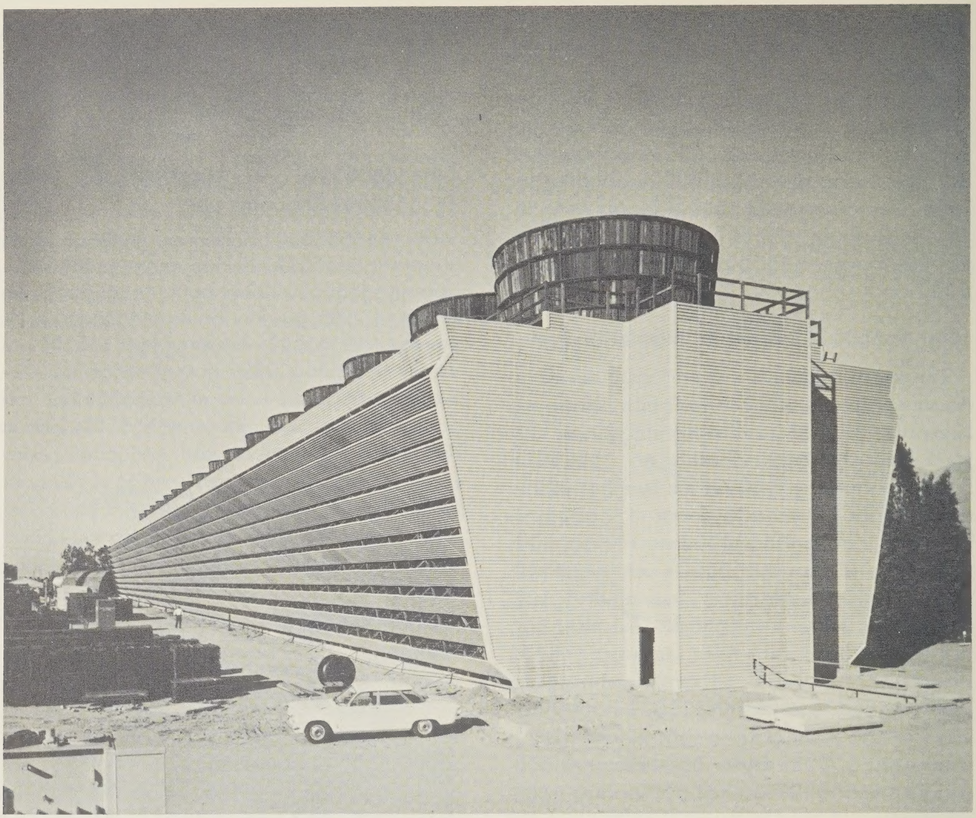

FIGURE 46 *The 576-foot long forced draft evaporative cooling tower at the Etiwanda steam-electric station of Southern California Edison Company provides condenser cooling for 666,000 kilowatts of generating capacity.*

675 gallons per minute, is required per megawatt of generating capacity. Thus, for a 4,000-megawatt generating station, the required condensing water would be 6,000 cubic feet per second and the minimum river flow would have to be about 12,000 cubic feet per second to limit the rise in temperature of the river water to 7° F.

Fortunately, there are several ways to make up for a shortage of cooling water, namely by recirculating the water in reservoirs, ponds, or cooling towers—both evaporative and nonevaporative. Each of these methods requires the supply of make-up water to replace that which is evaporated and otherwise lost. Cooling reservoirs and ponds require make-up water equal to about one or two hundredths of a cubic foot per second for each megawatt of plant capacity. Evaporative cooling towers require about two hundredths of a cubic foot per second and nonevaporative cooling towers about two thousandths of a cubic foot per second, per megawatt of plant capacity. Thus, for a 4,000-megawatt steam-electric generating station, the water requirement for a cooling pond would be 40 to 80 cubic feet per second, for an evaporative cooling tower system 80 cubic feet per second, but for a nonevaporative cooling tower system only about 8 cubic feet per second. Make-up water is obtained from surface or ground water sources.

Relative Costs of Cooling Systems

When an ample supply of cooling water is available, the once-through circulation method for condenser cooling usually has the lowest overall cost.

The recirculation system involving resorvoirs and ponds ranks next in economy.

There are two kinds of evaporative cooling tower systems—the induced-draft type and the natural-draft type. The induced-draft type usually has a slightly lower overall annual cost for generally comparable situations.

There are three types of nonevaporative cooling systems—the natural draft dry tower, induced-draft dry tower, and mechanical-draft, fin-tube exchangers. The dry type systems are in the developmental stages and it is still too early to forecast costs.

As indicated in Advisory Committee Report No. 7, the additional capital cost of a plant requiring a cooling tower system may be roughly estimated at $5 per kilowatt as compared with a similar installation utilizing conventional river water for the plant condensers. The burden of capacity reductions and increased fuel costs due to reduced efficiency may effectively double or triple this figure.

Effects of Air Pollution on Location of Large Plants

In locating large generating stations, special study is required of atmospheric conditions in the area, geographical surroundings such as hills and bodies of water, the sulphur content of the fuel burned, the type of combustion and air cleaning equipment with which the station will be equipped, and the degree to which the area is developed, including other nearby air polluting sources. Chapter 9 presents a detailed discussion of the air pollution problems.

Even with suitable modern furnace design, efficient dust collectors, proper plant layout and stack height, and under the meteorological conditions found at a particular plant site, the tolerable level of air pollution may in some instances tend to limit the size of the station.

It seems evident that expenditures for air cleaning equipment and extra-high stacks must be continued at their present levels of $5 to $10 a kilowatt for coal-fired plants if not increased. If the location of large generating stations is not to be severely limited, very high stacks are a necessity. Such stacks introduce cost increases from about 70 cents to $3 per kilowatt, invite objections because of possible hazards to air traffic, and face structural challenges because of sulphur corrosion problems.

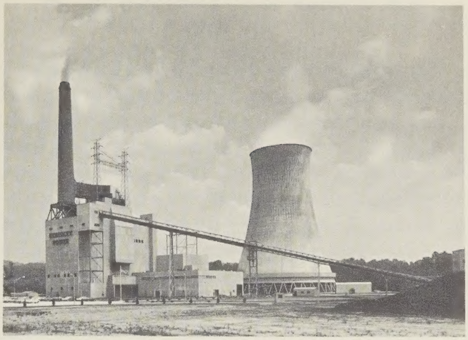

FIGURE 47 *The hyperbolic cooling tower, a relatively new form on the American horizon, is extensively used in other countries at sites where natural cooling water supplies are inadequate. This 320 foot high tower provides natural draft evaporative cooling for the single unit 265,000 kilowatt Big Sandy Plant at Louisa, Kentucky.*

At the Ohio Valley Electric Corporation's Clifty Creek plant at Madison, Ind., a 700-foot stack was placed in service in 1955 and at the Bull Run steam station of TVA near Knoxville, an 800-foot chimney is being constructed for the 900-megawatt generating unit. The outside diameter at grade of the Bull Run stack will be 65 feet and the inside top liner diameter, 28 feet. It is being constructed as two independently supported concentric reinforced concrete shells with an annular unventilated air space of about 3 feet between shells. The inner concrete shell will terminate with a 20-foot stainless steel section below the 800-foot top. It is designed to withstand mild earthquakes.

Fuel Availability—Mine-Mouth

In general, the location of generating stations is affected in various degrees by availability and cost of fuel. An adequate quantity of fuel of desired quality and an economical delivered fuel cost are basic to a decision as to where a large generating station is to be constructed. With respect to mine-mouth plants the magnitude of fuel reserves within a radius of several miles has to be sufficiently large to merit consideration for such a plant location. Here again the mine-mouth plant must be compared with possible alternatives to determine the most economical power source.

Ash Disposal and Commercial Use of Fly Ash

The problem of ash disposal is becoming increasingly difficult, especially in metropolitan areas, and it may be a minor economic factor to be weighed in plant location. Ash transportation costs must be considered. Usually, in thinly populated areas ash disposal can be accomplished by filling in nearby ground depressions or by depositing it on flat areas to significant height and later covering by earth overlay so as to create new more elevated land areas.

Millions of tons of fly ash are collected annually from steam-electric plants burning pulverized coal. The disposal of this waste material is costly, so efforts have been made to alleviate this economic loss through use of fly ash in the manufacture of portland cement, stabilization of soils, and as an admixture in concrete. These applications utilize large quantities of fly ash but the total use is only a small part of the supply. Last year the Consolidated Edison Co. of New York, Inc., completed a fly-ash sintering plant capable of producing 1,000 tons per day of lightweight aggregate for concrete. This new application has the potential for utilizing fly ash on a scale necessary to keep abreast of the large quantities produced. The use of fly-ash aggregate reduces the weight of concrete about 25 percent, and the concrete has proved satisfactory under laboratory testing.

Service Availability of Large Generating Units

In the rapid advances to higher pressures and temperatures and larger units for the steam-electric plants an important question remains to be fully answered, namely the amount of time each year that a generating unit is available for service. Unavailability for service or outage time is classified as:

(1) Scheduled—when the unit is out of service, periodically, for inspection, routine maintenance and general overhaul. These outages are usually referred to in terms of percent of time for a given period, ordinarily one year.

(2) Unscheduled—when the unit is out of service for emergency repairs, etc. This is generally referred to as "forced outage" time.

Advisory Committee Report No. 7 (see Part II) indicates through a series of experience charts a service availability of 82 to 90 percent for typical large high pressure, high temperature, "seasoned" units for the period 1955 through 1961. It is expected that with more experience these percentages will be improved. Repetitive design should be an important factor in such improvement. TVA which has the greatest number of large modern "seasoned" units in service, had during the years 1961, 1962 and 1963 average unit availability factors of 85, 87, and 89 percent respectively for some 50 units 125 megawatts and larger. Thirty of these units were in the 125/150 megawatts size range. Widows Creek No. 7, the only 500 megawatt unit operating in all 3 years, had availability factors of 83, 78, and 91 percent in this period. Two 650-megawatt units were initially placed in service in 1963.

The projection of future availability of these large units can best be approached in two steps.

First, there is the down-time for scheduled maintenance. This tends to be longer for the very large units. The large capital investment in such units presents a strong incentive to keep them in optimum operating condition which requires rigorous inspection and meticulous maintenance. Such maintenance is done and will continue to be done in the offpeak season to the fullest extent possible.

Second, there is the forced outage rate. Operating experience with units in the 400- to 650-megawatt range is quite limited since there were only nine units in this range in service at the close of 1963, with one in 1960, two in 1961 and six in 1963. Thirty-two units in the 300- to 399-megawatt range were placed in service in the period 1958 through 1963, giving a total of forty-one units, 300 megawatts and larger. This early sparse record which in reality covers only the so-called shakedown period indicates annual forced outages for the shake-down period are in the 8 to 12 percent range.

Semiautomation and automation should in the foreseeable future be making substantial contributions to reduced outage time. Safety of operation and the early detection of possible trouble so that preventative maintenance can be employed are strong factors favoring future automation.

Service outages, including the conclusions of Advisory Report No. 24 [4] which deals specifically with outage rates, are discussed in more detail in chapter 14.

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[4] Advisory Committee Report No. 24, p. 406 of Part II.

Large Unit Operating Characteristics

While the larger, high-temperature steam-electric units in sizes over 500 megawatts may eventually have operating flexibility comparable with the smaller units operating at lower temperatures and pressures, this will require a great deal more experience than has been accumulated with such units including experience at less than full load ratings.

The larger units during their earlier years will normally be operated at close to rated capacity to take advantage of lower heat rates. However, as they age and as newer units are added to meet load growth the new units take over the base load and the older units are relegated to offpeak service or taken off the line.

The use of computers to control the larger units may become general practice by 1980 and thus be of considerable value in overcoming these difficulties. A great many difficult problems will have to be solved before this stage of computerization is achieved. Eventually computer control of large units will make operation of units in capacities above 500 megawatts comparable to the record of smaller units.

Projected Life Cycle

There may be a tendency for the large units now going into service to spend more of their service life in base-load operation than has been true of previous units and for the utilities to construct low-capital cost and relatively high-fuel-cost special peaking units. Because steam-electric generation technology may have entered a period of diminishing returns with respect to higher thermal efficiencies, the pressure to displace older base-load units with newer base-load-type units will diminish.

Coordination of systems will help to increase system load factor. The effect of longer periods of high load factor operation under more severe conditions of temperature and pressure may be expected to reduce the service life of large units from the 35 years or more, now being experienced with units of lesser capacity, to about 30 years. This is the general opinion and conclusion reached in Advisory Committee Report No. 4 relating to retirement of generating equipment.[5]

Summary and Conclusions

Steam-electric plants have earned their position as the principal source of power supply for the electric utility industry. The impressive continuity in increasing unit size at an ever continuing economic gain, the progressive designs, and the bold advances into experimental extensions, have brought about lower capital costs, improved heat rates, and reduced costs of operation and maintenance. During the past decade the maximum size of turbine-generator units purchased has increased from 200 to 1,100 megawatts. The maximum unit size is expected by 1970 to be in the 1,000-1,200 megawatt range and by 1980 in the 1,500-2,000 megawatt range. However, a tempering effect on the application of the new large units may result from their higher outage rates and the diminishing rate of improvement in thermal efficiency and investment cost.

Considered by themselves, only the largest electric systems would be in position to take advantage of the economy of size of the large generating units. However, through proper coordination among systems on an area, regional, or interregional basis, these economies can be realized by all systems.

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[5] Advisory Committee Report No. 4, p. 26 of Part II.

CHAPTER 5

NUCLEAR POWER

Twenty-five years ago laboratory scientists first realized that energy released by nuclear fission in chain reactions could be used for electric power generation. In the intervening years the technology of nuclear power generation has moved from the laboratory to commercial plants. Considering the extreme difficulty and complexity of the technology, the pace of progress has indeed been remarkable.

The 970,000 kilowatts of nuclear electric generating capacity now in operation have demonstrated technical feasibility and practical reliability. While these first developmental plants have cost more than alternative conventional facilities, the prospects for nuclear power are now sufficiently promising to exert great competitive pressure. They have contributed both to major reductions in the price of coal and coal transport, and served as a powerful stimulus for improvement in alternative power generating sources.

In the future, nuclear energy will play an important part in setting ceilings for prices of power in an increasing number of locations. As nuclear ceilings are lowered in coming years the areas they cover will greatly broaden with resulting lower power costs to consumers.

Notwithstanding the excellent progress to date, the future of nuclear energy in the power industry depends on rates of progress along many difficult paths and also the extent to which improvements are achieved in reducing the cost of electricity from conventional plants. Conclusions are therefore subject to wider than usual variation, as influenced not only by the optimistic or pessimistic character of the analyst with respect to nuclear technology, but also by his familiarity with the prospects for advancement in competing sources of power supply.

The demonstration that nuclear power is practical and reliable is sufficient to assure its utilization in applications which take advantage of one or both of its two most important unique qualities. These are the ability to produce large quantities of electricity from a very small although not inexpensive inventory of fuel, and to operate without requiring combustion air which avoids releasing large quantities of combustion products to the atmosphere. These attributes alone, however, will not assure extensive use of nuclear energy as a source of electricity for the power industry in the foreseeable future. Nuclear power must offer electricity at a cost lower than other available means, if it is to be widely used. It is toward this end that the major research and development effort is now directed.

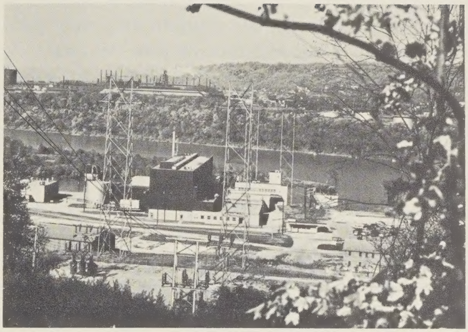

FIGURE 48 *The 60,000 kilowatt Shippingport Atomic Power Station near Pittsburgh, Pennsylvania, is the world's first full-scale nuclear plant used exclusively for civilian power production. The station, which began producing power in December 1957, is a joint project of the Atomic Energy Commission and the Duquesne Light Co.*

Energy Release from Fissionable Nuclear Materials

Like ordinary fossil fuel-fired plants, nuclear power plants use heat to produce steam to drive turbine generators. The kilowatts of power capacity and the kilowatt-hours generated from either source are undifferentiated and are transmitted and distributed in the same way. The major difference is that conventional thermal plants use heat produced by combustion of fossil fuel in a furnace, but nuclear plants use heat produced by fission of nuclear fuels in a reactor. Basically a nuclear reactor is substituted for a fossil fuel boiler.

In the fission process, if the nucleus of a fissionable atom, for example an atom of uranium isotope 235,[1] is struck by a neutron moving with suitable speed, the heavy atom will split apart into several lighter weight atoms (i.e., it will fission) and will emit radiation and neutrons. As a result of the fission, a very small part of the atom's mass is converted into energy which propels neutrons and other particles at high speed and thereby provides heat. A neutron released by fission of one atom can strike another atom of U^{235} and make it fission in turn. Continuation of this process constitutes the so-called "nuclear chain reaction." Chain reactions in a very small quantity of fissionable nuclear material can cause fission of billions of individual atoms which together can release great quantities of heat.

Fission of about one half of 1 percent of 75 tons of nuclear material in a 500-megawatt nuclear power plant of contemporary design will produce heat in a year roughly equivalent to the heat from burning a million tons of coal in a 500-megawatt conventional power plant. Accordingly, fuel transportation costs for nuclear plants are de minimus and nuclear plants may therefore be located far from sources of nuclear fuel and closer to markets. In areas in which fossil fuel costs are relatively high, nuclear plants may thus be able to remove as a handicap to economic progress the former high level of energy costs.

Conversion of Fertile Materials to Fissionable Materials

A key step in the process of utilizing nuclear energy to generate electricity is the conversion of materials rich in nuclear energy into fissionable materials. The only significant material subject to nuclear fission in its natural form is the isotope of uranium designated U^{235}. Uranium as mined is about 0.7 percent U^{235} and 99.3 percent U^{238}. Uranium isotope 238, which is not generally fissionable in its natural state, contains approximately 140 times as much of the basic raw material resources of natural uranium as uranium 235 which is fissionable. Fortunately, uranium 238, which is called a fertile material, can be converted into plutonium 239, which also is fissionable in a nuclear reactor. Some of the plutonium formed during operation of the reactor will fission and release energy. The rest of the plutonium produced in the reactor (and unused U^{238}) can be removed during discharge of the used fuel, and can be separated chemically either to be reinserted as fresh fuel into the same reactor, or inserted into other reactors, to produce additional energy. This so-called "plutonium re-cycle" can be repeated in several successive stages, and thus would be able to convert part of the fertile U^{238} to fissionable plutonium. The process is still difficult to accomplish economically because the radioactive character of plutonium precludes direct handling and requires remotely controlled operation, processing, and maintenance to achieve safety. However, experts anticipate that within several years the plutonium re-cycle will be providing more nuclear energy from a unit of uranium ore than obtainable from the fissioning of the small amount of uranium 235 which it contains.

Thorium available in a natural state is mostly composed of thorium isotope 232 (Th^{232}), which generally does not fission but which is fertile and can be converted to uranium isotope 233 (U^{233}), which can fission and release energy. However, considerable time and effort may be needed to develop processes to cope with the radioactivity[2] which accompanies U^{233} before that material can be utilized at low cost.

Fast and Thermal Reactors

The various reactor concepts can be divided generally into two classes, "fast" reactors, and "thermal" reactors. The terms refer to the relative speeds of the neutrons which cause the fissioning process in the reactor to continue. Neutrons, when first emitted during fission, move rapidly and are called fast neutrons. Neutrons which start at high speed can be slowed down to thermal speed by deliberate insertion of materials specially chosen for this purpose, called moderators. Almost all of the nuclear power plants now in operation depend primarily on thermal neutrons to maintain the nuclear reaction.

Fast reactors have high concentrations of fissionable material, and are relatively compact but complex. In a fast reactor, the life cycle of neutrons is much shorter than in thermal reactors. The speed of reaction makes operation of the fast reactor more difficult to control. The concentrated fuel in a relatively small volume in the fast reactor also represents a large investment. Thus it would be desirable to operate the reactor at a very high rate of heat generation so that the fixed charges on the fuel investment could be spread over a large number of units of energy output. Difficult engineering and metallurgical problems must be overcome to remove heat at the rates dictated by economy.

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[1] Most elemental materials exist in several slightly different forms which reflect small differences in the number of neutrons in their atomic structure. The different forms of the same element are known as isotopes.

[2] The radioactivity arises from the slow decay of U^{232}, small amounts of which accompany the formation of U^{233}.

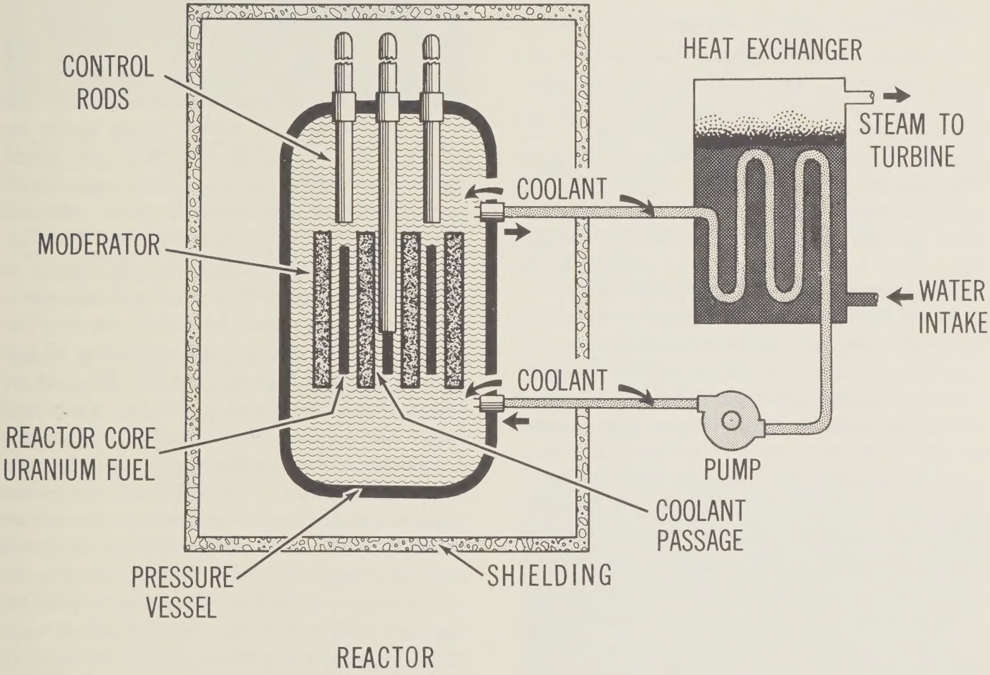
PRINCIPAL COMPONENTS OF A NUCLEAR REACTOR

FIGURE 49 *This simplified diagram depicts the principal components of a nuclear reactor. In some reactors the coolant serves also as the moderator and in other types the heat exchanger is eliminated. In some types of reactors, the coolant is a liquid, in others it is a gas.*

Economically, it is desirable that as large a proportion as possible of the neutrons released in the reactor should be used to produce new fuel. The fast reactor is generally superior in this respect, due primarily to two factors: (1) more neutrons are released in fissions caused by fast neutrons, so that there are more excess neutrons available to be absorbed by fertile isotopes; (2) fast neutrons are less likely than are thermal neutrons to be absorbed and wasted in the structural materials of a reactor. This means that fast reactors typically can produce more new fuel per unit of fuel consumed than can thermal reactors. A reactor capable of producing more fuel than it consumes is called a "breeder" reactor.

Experts differ as to whether it would be best to use thorium with neutrons slowed to thermal speeds to achieve breeding, or whether it would be best to use uranium and fast neutrons to produce plutonium to achieve breeding. It is conceivable that both of those processes may be used in the future in order to provide more complete utilization of available nuclear fuel resources. Because no one can determine now the relative advantages and disadvantages of various alternative or combinations which may prove to be most beneficial for future energy supply, research and development is proceeding on both approaches.

Development of Nuclear Technology and Nuclear Power Plants in the United States

Extensive efforts in physics, chemistry, metallurgy, radiological and health sciences, and engineering during the past 25 years have provided a foundation for nuclear power generation. Programs in nuclear weapons production and naval ship propulsion have provided major industrial capabilities including facilities for large volume nuclear material enrichment and chemical processing. These activities have been of great value for development of civilian nuclear power plants.

The U.S. domestic nuclear power program has included a wide spectrum of research, design, construction and operation of a number of experimental and small prototype nuclear power plants to explore a broad range of reactor types. Many concepts of thermal reactor power plants have been studied and tried. These have included the use of fissionable uranium (U^{235}) fuel, and in some instances plutonium or U^{233}, in various concentrations and in metallic and ceramic materials with various protective coatings, such as stainless steel, and zirconium alloys, and in various physical configurations, such as rods, plates, and tubes, and even in fluid form as liquid metals, molten salts, or slurries. Heat may be removed from the fuel by circulation of ordinary or heavy water, steam, gas, organic liquid, and liquid metals. The moderator which slows down movement of the neutrons may be ordinary water, heavy water, graphite, beryllium, or organic fluids. The heat-removing fluid may also serve as the moderator. In general, the goals are a simple, economical fuel and reactor system from which heat can be extracted at high rates and high temperatures and a fuel form which can be operated for a long time without replacement. In addition, neutrons should be conserved for production of as much new fuel as practicable.

Early stages of civilian nuclear development have been accelerated by Government expenditures which the Atomic Energy Commission estimates totaled $1,275 million by 1963. These programs have included financial assistance to privately owned projects, research in Government laboratories, savings to individual companies from the use of the Government's large volume fuel preparation and processing, and waste disposal by the Government for national security programs. Other assistance has included "buyback of plutonium" or waiver by the Atomic Energy Commission of rental charges for nuclear materials during early years of nuclear power operation.

Both government and industry recognize that when specific types of nuclear power plants approach levels competitive with fossil fuel plants, further development of these reactor types should proceed without government financial assistance. The industry will be assuming financial independence in other ways. Legislation was enacted in August 1964, which in effect requires private ownership of new fuels needed for reactor use after December 31, 1970, and calls for terminating all outstanding leases of fuels by June 30, 1973. At the present time all irradiated nuclear fuel is processed by the AEC. However, a privately owned processing plant is now under construction and others are being contemplated. The AEC will discontinue processing of private reactor fuel as soon as private processing plants have the capability of doing such work at a reasonable cost. This action represents another step by the Federal Government to place the nuclear reactor industry on a true commercial basis. However, the frontiers of research and development for further new scientific and technical advances in perfecting breeder reactors and other more advanced nuclear reactors will still need Government sponsorship and financial aid.

Nuclear Power Plants Already Operated or Nearing Operation

Thirteen civilian nuclear power plants,[3] in the United States, varying in sizes from 11,400 kilo-

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[3] Figures 48 through 51 and 121 and 130 illustrate a few of these plants.

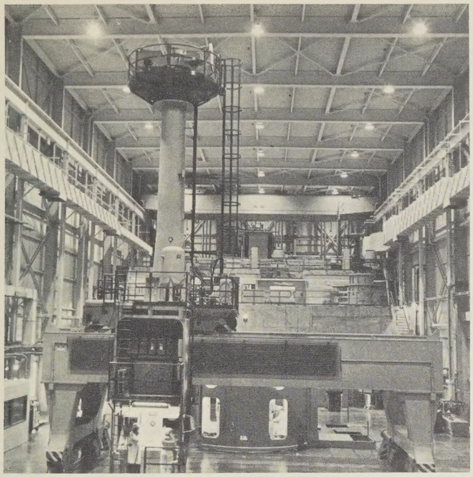

FIGURE 50 *This fuel handling machine at the Hallam Nuclear Power Facility near Lincoln, Nebraska is used to exchange new and spent fuel elements in the sodium-graphite reactor located beneath the circular control rod mechanism housing (bottom center of photo). The mast is heavily shielded to protect plant personnel from the high degree of radiation given off by fuel elements withdrawn from the reactor for transfer to storage cells.*

watts [4] to 200,000 kilowatts, with a combined net capability of about 970,000 kilowatts, are now considered operable. Three of these are pressurized water plants, six are boiling water, one has a sodium cooled-graphite-moderated reactor, one is organic moderated and cooled, one uses heavy water for coolant and moderator, and one is a sodium cooled fast breeder.[5] These plants are listed in table 28 with their individual capacities, start-up dates, and other relevant information.

Table 29 presents similar data for the five major plants now well under construction and expected to be placed in service in 1965 to 1967. The total capacity of these five plants will be about 1,730,000 kilowatts. The largest plant in this list, rated at 800,000 kilowatts, is also unique in that it is a dual-purpose plant. The reactor, a plutonium production reactor at Richland, Wash., first went critical in 1963. It is owned by the United States and operated as one of AEC's defense facilities. The by-product heat which it generates will be used to drive turbines at a power plant being constructed for the Washington Public Power Supply System. For these plants (except the special case of the dual-purpose plant) the cost of power produced will be higher than that from alternative conventional sources.

Current Development of New Large Nuclear Power Plants

Three additional plants not yet under construction but scheduled for completion by 1968 are listed in table 30. Their aggregate capacity is some 1.5 million kilowatts. All are water reactor plants and each is considerably larger than any of the existing U.S. nuclear plants except the Hanford dual-purpose plant.

Utilities are sponsoring these major plants for start-up between 1967 and 1968. Their action indicates confidence by utility management officials that there will materialize the engineering improvements, increased outputs, fuel cost reductions in subsequent core loadings and other anticipated im-

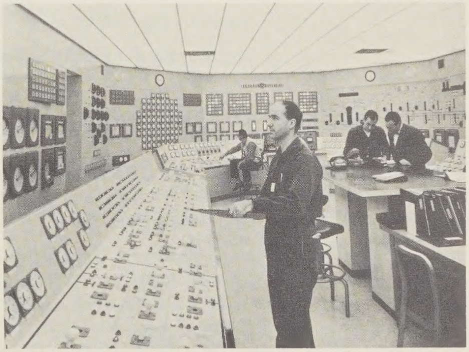

FIGURE 51 *The control room of Dresden Nuclear Power Station permits monitoring the operation of the project, including the many instruments, controls and devices installed as added safety features. This 200,000 kilowatt generating plant of the Commonwealth Edison Company was the first full scale privately financed nuclear power station.*

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[4] Reactor engineers frequently differentiate between the heat capacity of a reactor, mw(t), and the electrical capacity of the plant, mw(e). Typically it is feasible to convert only about a third of the reactor's heat energy into electrical energy. In this chapter all figures expressed in kilowatts (kw) or megawatts (mw) refer to electrical output.

[5] The fast breeder, though having a nominal electrical capacity of 60,000 kw (equivalent to about 200,000 kw heat capacity) is still limited to very low power level operation (1 mw heat capacity). Operation at higher power levels will be sought beginning this year.

TABLE 28

Operable Nuclear Power Plants [1] as of July 1, 1964

Name, owner or operator	Location	Type	Capacity net kw	Startup
Shippingport Atomic Power Station (AEC and Duquesne Light Co.).	Shippingport, Pa	Pressurized water	60, 000	1957
Dresden Nuclear Power Station (Commonwealth Edison Co.).	Morris, Ill	Boiling water	200, 000	1959
Yankee Nuclear Power Station (Yankee Atomic Electric Co.).	Rowe, Mass	Pressurized water	175, 000	1960
Big Rock Nuclear Power Plant (Consumers Power Co.).	Big Rock Point, Mich	Boiling water	72, 000	1962
Elk River Reactor (AEC and Rural Cooperative Power Association).	Elk River, Minn	Boiling water	23, 000	1962
Hallam Nuclear Power Facility, Sheldon Station (AEC and Consumers Public Power District).	Hallam, Nebr	Sodium graphite	75, 000	1962
Indian Point Unit No. 1 (Consolidated Edison Co. of New York, Inc.).	Indian Point, N.Y	Pressurized water	[2] 255, 000	1962
Carolinas-Virginia Tube Reactor (Carolinas-Virginia Nuclear Power Associates, Inc.).	Parr, S.C	Pressure tube, heavy water.	17, 000	1963
Enrico Fermi Atomic Power Plant (Power Reactor Development Co.).	Lagoona Beach, Mich	Fast breeder	60, 900	1963
Humboldt Bay Power Plant, Unit No. 3 (Pacific Gas & Electric Co.).	Humboldt Bay, Calif	Boiling water	50, 500	1963
Piqua Nuclear Power Facility (AEC and City of Piqua).	Piqua, Ohio	Organic cooled and moderated.	11, 400	1963
Boiling Reactor Nuclear Superheat Project (AEC and Puerto Rico Water Resources Authority).	Punta Higuera, P.R	Boiling water, integral nuclear superheat.	16, 300	1964
Pathfinder Atomic Power Plant (Northern States Power Co.).	Sioux Falls, S. Dak	Boiling water, nuclear superheat.	58, 500	1964

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[1] Based on tables included in AEC report TID–8200 (10th revision).

[2] Approximately two-thirds contributed by the nuclear reactor and one-third by the oil-fired superheater.

TABLE 29

Nuclear Power Plants Under Construction [1] as of July 1, 1964

Name, owner or operator	Location	Type	Capacity net kw	Startup
Peach Bottom Atomic Power Station-HTGR (Philadelphia Electric Co.).	Peach Bottom, Pa	Gas cooled, graphite moderated.	40, 000	1965
La Crosse Boiling Water Reactor (AEC and Dairyland Power Cooperative).	Genoa, Wis	Boiling water	50, 000	1965
Hanford New Production Reactor (AEC and Washington Public Power Supply System).	Richland, Wash	Pressure tube	800, 000	1965–6
San Onofre Nuclear Generating Station (Southern California Edison and San Diego Electric Co.).	San Clemente, Calif	Pressurized water	375, 000	1966
Connecticut Yankee Atomic Power Station (Connecticut Yankee Atomic Power Co.).	Haddam Neck, Conn	Pressurized water	462, 000	1967

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[1] Based on tables included in AEC report TID–8200 (10th revision).

TABLE 30

Planned Nuclear Power Plants Announced[1] as of July 1, 1964[2]

Name, owner or operator	Location	Type	Capacity net kw	Startup
Malibu Nuclear Plant (Los Angeles Department of Water and Power).	Corral Canyon, Calif..	Pressurized water.....	463, 000	1967
Nine Mile Point Plant (Niagara Mohawk Power Co.).	Oswego, N.Y.........	Boiling water.........	500, 000	1968
Oyster Creek Station (Jersey Central Power & Light Co.).	Oyster Creek, N.J....	Boiling water.........	515, 000	1968

[1] Based on tables included in AEC report TID–8200 (10th revision).

[2] The announced proposal to construct a 325,000-kilowatt nuclear plant at Bodega Bay has recently been dropped.

provements in performance and costs on which the advantages of these projects are based. The Oyster Creek Station, the most recently announced project of this group, will be constructed at a cost per kilowatt considerably less than that of any earlier plant. This and other recent proposals appear to mark the beginning of marketing practices by major nuclear reactor manufacturers which take into account the opportunities for repetitive use of established reactor designs.

The program of nuclear power plant development summarized in tables 28, 29, and 30, represents the results of a program of cooperation between industry and Government. Over the years many difficulties were overcome and an enormous scale of both executive and technical effort was required to bring these projects into being. In this effort, thousands of Government and industry people have been trained in a new technology, and have achieved a high degree of competence and a capability for much further development of nuclear power for civilian use.

Effect of Unit Size and Output on Capital and Operating and Maintenance Costs

As previously noted, the nuclear power plant is much like a conventional steam plant except that a nuclear reactor is used instead of a furnace burning fossil fuel. Shielding must be provided to avert hazardous radiation during normal operation, and special containment facilities and other safeguards must be incorporated to control the escape of radioactive material in the improbable event of a reactor accident. For these and other reasons, a nuclear plant is likely to have higher construction costs than a conventional plant. However, comparative design studies have indicated that the capital costs per unit of capacity for a nuclear plant should decline even more rapidly with increasing capacity than do conventional plant costs. Accordingly, the capital cost disadvantage of nuclear plants in comparison with conventional plants will be less significant for larger plants.

More specialized operating staff and higher maintenance costs for some equipment are required for nuclear than for conventional plants. Accordingly, nuclear plants have been relatively more expensive to operate and maintain than conventional plants. However, this difference is expected to decline with increasing nuclear plant capacity and greater operating experience.

Fuel Cycle Costs

Fuel cycle costs estimated by AEC in its Report to the President in November 1962, anticipated a substantial improvement by 1980 of the energy yield in subsequent fuel loadings in either the present types of water reactors or in improved reactors. In more recent quotations for new plants, nuclear suppliers have anticipated simplification and improvement in fuel fabrication and other fuel cycle improvements, and quotations have assumed lowered cost achieved by larger volume of sales.

These potential improvements point in the direction of increased output over initial design capacities, decreased unit costs in dollars per kilowatt of capacity, and decreased fixed charges and fuel cycle and other costs per kilowatt-hour.

Larger Unit Capacities

In view of the sharp effect of increases in unit size in reducing the cost of nuclear power, the maximum sizes in which it is possible to build nuclear plants is of special interest. As shown in table 28, the largest nuclear plant now in operation in the United States has a capacity around 200,000 kilowatts. The present plants are single reactor, single turbogenerator plants. In view of the good experience with water reactors, most manufacturers are now ready to provide single reactor, single turbogenerator stations in sizes up to about 500,000 kilowatts to 600,000 kilowatts. The more experienced builders consider single units of 700,000 to 1,000,000 kilowatts to be feasible with little additional development work.

An important factor tending to limit the size of water reactors is the dimensions of the reactor pressure vessel. An 11-foot internal diameter is about the extreme upper limit for a vessel that can be shipped by rail. It can contain the fuel assemblies for roughly a 300-megawatt to 400-megawatt pressurized water plant, or a 100- to 200-megawatt boiling water plant.

Manufacturers now believe they could make a vessel up to nearly 17 feet internal diameter which would be suitable for a 1000-megawatt pressurized water plant. Such a vessel would weigh some 600 tons. Since a boiling water reactor operates at a much lower pressure than a pressurized water reactor, its pressure vessel can be built to a larger diameter without exceeding vessel wall thickness limitations. Perhaps a vessel up to nearly 26 feet in internal diameter could be considered for a boiling water plant. This may permit a capacity of about 1500 megawatts.

Such huge pressure vessels could be transported by barge or specially designed trailer. However, few highways afford the necessary vertical clearances. Field construction of such large vessels is probably technically feasible but would require essentially a temporary and costly full-scale shop at the site. Practically, therefore, very large steel vessels could be installed only at sites which are reasonably accessible by barge. While this limitation may seem serious at first thought, it may not prove unduly restrictive. The majority of the Nation's population centers are in proximity to our extensive coastline or to large lakes and rivers which are commercially navigable and which in addition can supply the enormous cooling water demands of very large plants. Other less well developed types of nuclear reactors may be placed in commercial operation in the next 10 to 15 years which are more adaptable to partial fabrication and assembly on the site and thus provide a basis for larger scale nuclear generation in locations not accessible to water transportation.

Nuclear Power Stations with Several Reactor Units

Construction of mammoth nuclear electric power stations with several reactor units at one site may be anticipated. The handicap of rigorous site requirements could be overcome, at least in some degree, by building several reactor units at a single site. This assumes that the individual reactors are sufficiently independent so that an accident with one would not significantly increase the chances of accidental release of radioactive material from another. In this case an exclusion area larger than that provided for a single reactor probably would not be necessary. Unit costs could also be reduced by sharing of fuel handling and other facilities among the units, and perhaps in the case of some designs, by the use of common containment.

Fully exploiting the multiunit approach could result in a very large capacity nuclear station, suggesting the possibility of several utility systems joining forces to establish a nuclear generation center. While such a development would conserve nuclear plant sites, the economies of construction and operation would have to be balanced against the extra costs of transmitting the power from a single source throughout extensive market areas. The establishment of a large capacity transmission grid covering broad areas of the country, which later chapters in this Report suggest are economically feasible, would tend to minimize the transmission costs and enhance the potential savings in the construction of such a nuclear complex.

Nuclear Plant Capacity Factors

Estimates of nuclear plant production costs generally employ the assumption that the long-term average output of nuclear plants will be about 80 percent of maximum capacity. Insofar as availability is concerned this assumption may even be conservative. Considering the generally low pressures and temperatures in the nuclear steam cycle of contemporary water reactors designs, the nuclear turbogenerators and heat exchangers of these reactors may prove relatively dependable compared to today's high temperature conventional plants. Reactor refueling, maintenance, and other factors could account for offsetting sources of outages for nuclear plants in comparison with conventional plants. Attempts are being made to reduce outages for refueling. For example, some reactor designs provide for on-line refueling but it may be that the cost of the equipment to expedite this operation will be greater than the savings.

Availability itself may not control the extent to which a particular nuclear plant will be used. Load conditions, and possibilities for use of other low cost alternatives including improved nuclear plants, will determine the load factor of each plant. Considering the fuel cost advantages likely for large reactors, it is expected that large nuclear plants will be favored for the highest level of output in the system complex. At times during the prime years of the plant's life nuclear units may operate at plant factors between 80 and 90 percent, declining subsequently as lower cost base load plants, probably of improved nuclear type, are added to the system. The pattern should follow that of conventional plants except that nuclear plants will be used at higher load factors, because of their lower operating costs.

Flexibility of Nuclear Plant

The prediction of base load operation, as discussed above, is appropriate for the early economically competitive nuclear plants, but it may not be appropriate for all plants when nuclear power becomes a substantial fraction of a system's power supply. Typically, minimum night-time system loads are only about a third of the day-time peaks. When more than this fraction of the peak is supplied by nuclear plants, there must be some reduction in off-peak output to follow the load decline. Further increases in the nuclear capacity will then require that these plants be increasingly prepared to "follow" the system load variation. All experience thus far indicates that nuclear plants have excellent loading flexibility—actually superior to large conventional steam units. However, future nuclear plants designed for high pressure and temperature operation may lose this margin of superiority.

Radiation Hazards and Safeguards to Protect Public Health

Nuclear fission is accompanied by the emission of direct radiation and by the formation of a variety of radioactive fission fragments that will emit radiation over various time periods during which they decay. Therefore, it is imperative to provide safeguards to avoid contamination of the working areas of the plant and the environment surrounding the plant.

Government and industry have acted in three ways to avoid serious consequences: (1) by safeguards to prevent or to reduce to minor levels normal routine release or accidental release of hazardous radiation and radioactive products within the reactor structure; (2) by containment structures and other safeguards to keep within the plant any accidental release of hazardous radiation which occurs; and (3) by zoning measures to prevent whatever radiation and radioactive products may escape inadvertently, in spite of multiple safeguards, from causing harm to the inhabitants in the vicinity.

It is difficult to determine the kinds and extent of radiation doses which under innumerably different kinds of conditions should be regarded as likely to cause harm. The Atomic Energy Commission, international agencies, and others have evolved standards and criteria based upon exposure data and expert judgment as to what limitations and requirements may be essential to achieve adequate protection. Further experience may lead to tightening or relaxing the criteria which may be applied in the future.

The AEC has placed much stress on safety in its civilian nuclear program. Research and development in radioactive waste management has been underway for many years, and a companion program in reactor safety was started in 1955. An expanded and accelerated program was initiated in 1961 which includes a wide range of engineering scale tests and evaluation studies relating to reactor safety.

The chance that some accident might occur has led to major efforts to reduce the likelihood of accidents and minimize the consequences, efforts which to date have been highly successful. To assure a high degree of safety, nuclear reactors must be designed and operated with the utmost care to reduce the probability of accidental dissemination of radioactive products. These safeguarding steps must include great care in plant design, extensive instrumentation and monitoring, requirements for precision and reliability of components, provision of multiple auxiliaries and services to reduce risks of equipment or operating failure, special care in fuel handling and storage, provision of shielding and structural and operating safeguards intended to contain direct radiation and radioactive fission products, appropriate means for controlled release of radiation when desirable, rigorous control to assure proper construction, operating procedures, and maintenance, and frequent inspection and testing of all safety procedures and equipment.

The radiation hazards of a nuclear accident can be further reduced by prescribing restricted or exclusion areas in the plant vicinity. Thus, if substances emanating from a reactor must travel several miles through the air before they can reach substantial numbers of people, their hazardous character can be reduced not only by natural dispersion and dilution in the atmosphere but also through partial decay of the radioactive and toxic products during the time of movement out of the restricted zone. Therefore, AEC has utilized distance from the reactor to people as one of the several safeguards in nuclear plant site selection criteria.

Each situation must be analyzed individually but the following figures estimated for a water reactor plant are roughly indicative of the effect of present AEC requirements. A reactor with an electrical output of 500 megawatts probably would have an exclusion area with a radius of about 0.9 mile, which is equivalent to about 1,600 acres. The low population zone would extend to roughly 14 miles from the plant. The reactor site would be required to be no nearer than about 18 miles from the nearest population center of about 25,000 people. Of course as further knowledge and experience is gained these distances may be adjusted.

The possible effect of earthquakes is an additional question often raised in connection with the location and design of nuclear plants in earthquake-prone areas. A recent AEC report on earthquakes [6] analyzes various ways in which earthquakes might cause mechanical or structural failure and disrupt plant equipment, services, or protective controls and thereby produce effects on reactors which could lead to more severe consequences. The analysis outlines the special considerations and precautions in site selection, design, and engineering to be taken in the planning and construction of the plant to offset the effect of unusual seismic forces. The geological conditions at sites for nuclear plants proposed for an earthquake-prone area must receive especially thorough examination and all parts of the facility must be checked for strength and functional performance to resist the shock loadings that can be imposed by severe earthquakes.

Accidents can happen but in view of the multiple safeguards and precautions built into a nuclear plant a combination of events which could produce a nuclear accident involving harmful radiation effects in inhabited areas is extremely improbable. If any reasonably conceivable accident were to occur, such as a break or major leak in a line of the primary cooling system, ultimate release of harmful radiation would not occur except as a result of a series of failures of safety features. A breakdown of all of the numerous independently operative safety controls for stopping the reactor process must have occurred before the nuclear material conceivably could melt down and produce heat and pressure which could cause radiation and radioactive products to escape from the reactor area. Even then no public harm would result without the further combination of the failure of the containment shell or suppression chambers to retain the radioactive materials. If some of the radioactive material did escape from the plant, it would be subject to the effects of decay and dilution in reaching inhabited areas. The consequences of any nuclear accident are greatly minimized by the criteria, standards and procedures employed by AEC in the licensing, testing, operation, maintenance, and inspection of nuclear projects. The safety record in the operation of utility sponsored nuclear-electric plants to date has been exceptionally good.

Nuclear Plant Locations and Air Pollution

Increasing efforts to reduce air pollution may advance the consideration of nuclear power plants in some areas. These plants do not release hydrocarbons or other chemical substances which could contribute to air pollution problems. Should much more elaborate and expensive air cleaning equipment than that now in use be demanded of conventional plants, this increased cost would make nuclear power plants relatively more attractive.

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[6] AEC—Technical Information Document—7024. *Nuclear Reactors and Earthquakes August 1963.*

While it is likely that an extended record of good experience will be required before nuclear plants are built in close proximity to densely populated load centers, this does not mean that the beneficial effects of nuclear plants in reducing air pollution is not already of value. There are few locations where major new conventional plants would be located where freedom from atmospheric pollutants would not be a valuable feature.

Nuclear Hazard Insurance

Liability insurance presents special problems for nuclear power plants. Experience to date has been limited to a few years and a small number of plants. Accidents have been few in number and damage small, but there is little statistical basis for establishing risks. Meanwhile, conceivable risks and liability have been considered to exceed the financial capability of the private insurance industry. Accordingly, Congress in 1957 authorized the Federal Government to provide liability protection up to $500 million for any single nuclear accident. The reactor operators have paid the Government an annual fee of $30 per megawatt of reactor heat capacity for liability coverage. This usually amounts to about $100 per megawatt of electrical capability.

Owners are required to secure the prescribed amount of private liability insurance up to a limit of $60 million, depending upon size of nuclear plant, as a prerequisite to licensed operation and procurement of federally sponsored liability protection. This is in addition to the Federal liability insurance. Insurance company premiums for nuclear plants are at present higher than premiums for conventional operations.

Basic Assumptions in Projecting Nuclear Capacity

It has been the national policy, in seeking to overcome initial economic hurdles in the development of nuclear reactors and support facilities, to have the Federal Government absorb part of the cost of early nuclear plants. Cost support has taken several forms, such as providing research and development, design, and construction assistance; providing fuel and fuel-cycle services at less than full cost; and paying premium prices for new fuel produced in reactor operation. Manufacturers also have assisted in nuclear development by providing equipment at less than normal profit, and utilities have made substantial research and development expenditures.

However, any considerable nuclear power industry must stand on its own financial feet. Estimates of nuclear power costs used in this Survey are generally predicated on a large-scale nuclear power industry and escalation of unit sizes well above those that have been built to date. The scale of nuclear capacity additions projected later in this survey is based on assumptions of cost believed to be consistent with private ownership of plant and fuel, fuel manufacturing, and reprocessing facilities, and normal profits for equipment manufacturers. It is assumed, however, that the Federal Government will continue to participate to some extent in hazard insurance against nuclear loss beyond private coverage.

The projection of nuclear power generating capacity has been made without investigation to determine actual availability of satisfactory sites.

Wide Range in Conditions and Plant Costs

There can be a wide spread in the unit cost of power from a nuclear plant depending on the plant location, size, and design. Some of the factors which account for the variation in cost are differences in reactor type and size, the capacity achieved under actual operating conditions, accessibility for transportation of pressure vessels and other major items of equipment, site conditions, the type and expense of condenser cooling systems, local levels of construction costs, and needs for transmission to load centers. The cost of generation from competing fossil-fired steam plants can also vary significantly from area to area for many of the same reasons and in addition because of the variation in the type of fuel used as it affects the design of the plant and the cost of fuels.

The important point to keep in mind is that the competitive relation between nuclear plants and conventional alternatives can vary markedly from one region to another throughout the country. This is true not only because conventional plants are more economical in the coal and gas fields but because nuclear costs vary from region to region. General comparisons have only limited value.

Estimated Range of Future Nuclear Costs and Competitive Levels to 1980

During the early part of 1963, the Subcommittee on Nuclear Development of the Generating Stations Special Technical Committee made an analysis of cost trends of nuclear power stations. Their studies indicated substantial declines in costs for plants installed between 1967 and 1980. Since the Subcommittee completed its analysis, major nuclear manufacturers have better defined their intended lines of production and have announced prices considerably below the expected levels. For that reason the Commission's staff has prepared revised estimates to reflect these changed circumstances in its projections of potential nuclear use by 1980.

The rough staff estimates summarized in table 31 may serve as a general indicator of the competitiveness of water type nuclear plants with alternative conventional plants anticipated between now and 1980. The tabulation records the assumed differentials in capital and operating costs between nuclear and coal-fired conventional plants and concludes with a competitive rating of nuclear generation expressed as a range in coal costs in cents per million Btu.

Dates assumed for initial operation, and the "name plate" (net) capacities assumed to be available on those dates are shown respectively on lines 1 and 2 (of table 31). Amounts by which the capital costs of nuclear plants are estimated to exceed capital costs of conventional fossil fuel plants, expressed in dollars per kilowatt of expected plant net capability, are shown on line 4. The lower limits of estimated capital cost differentials reflect the assumption that nulcear plant capabilities may prove to exceed nominal capacities by between 10 to 20 percent. Capital cost differentials are translated into mills per kilowatt-hour in line 5. Line 6 shows the amounts, expressed in mills per kilowatt-hour, by which the operating and maintenance costs for nuclear plants may exceed those for conventional plants. The figures include the cost of nuclear hazard insurance. On line 7 is shown the estimated range of total fuel cycle costs for the nuclear plants.

The estimated nuclear fuel costs are those expected to be attained after the first core is exhausted, 3 to 5 years after the indicated date of initial service. The figures are estimated on the basis of private ownership of fuel after 1970. Line 8 is the total of lines 5 through 7 and thus is the amount, in mills per kilowatt-hour, by which total nuclear power costs may be estimated to exceed conventional plant costs exclusive of coal costs. In other words, if the conventional plant had a fuel cost, in mills per kilowatt-hour, just equal to the appropriate figure on line 8, its total costs would be the same as the total costs of the nuclear plant. The "break-even" fuel costs of line 8 are translated into cents per million British thermal units in line 9. That is, if the cost of coal delivered to a conventional plant is higher than the indicated figure in cents per million British thermal units, the nuclear plant would be more economical. Thus, if a 300-mega-

TABLE 31

Approximate General Range of Competition Between Nuclear and Coal Fired Generation

1. Year plant placed in service	1967	1970	1975	1980
2. Nominal plant output—kilowatts	300, 000	500, 000	1, 000, 000	1, 200, 000
3. Projected investment cost of alternative conventional plant (reference base for line 4)—$/kw	130	122	110	107
4. Approximate additional investment cost of nuclear plant compared to alternative fossil fuel plant. Dollars per kw of capacity	40–60	10–30	0–15	0–12
5. Effect of additional investment in nuclear plant on energy cost—mills per kwh	0. 7–1. 1	0. 2–0. 5	0–0. 3	0–0. 2
6. Effect of additional operation and maintenance of nuclear plant on energy cost—mills per kwh	0. 3	0. 2	0. 1	0. 1
7. Nuclear fuel cost—mills per kwh	1. 8–2. 1	1. 5–1. 9	1. 2–1. 6	1. 0–1. 4
8. Cost of fossil fuel—in mills per kwh (total of items 5, 6, 7) at which total power cost of nuclear generation or fossil fuel generation would be about equal under generalized conditions assumed herein. (Referred to as "break even" cost.)	2. 8–3. 5	1. 9–2. 6	1. 3–2. 0	1. 1–1. 7
9. Break-even fossil fuel cost in item 8 converted to cents per million Btu of fossil fuel cost	31–39	21–29	15–22	12–19

watt nuclear plant placed in service in 1967 and costing $40 per kilowatt more than a conventional coal-burning plant obtained its fuel at the minimum predicted price, it would be expected to be fully competitive with its coal-burning alternative using 31 cents per million British thermal units coal by about 1970.

By about 1975, large nuclear plants are projected to be competitive with coal in the 15–22 cents per million British thermal units range, and by 1980, in the 12–19 cents range. At the lower range, nuclear plants would be able to compete successfully as the supplier of most of the expanding utility energy requirements. This will bring strong pressures to bear on other energy forms to find ways to lower their costs and so extend the period of competition. In any event, the electricity consumers are sure to gain in lower costs for electricity.

The cost of conventional coal fired generating plants will decrease with increasing unit size, and with improvements in plant design and construction. The increments in cost of nuclear plants in relation to conventional plants as given in line 4 of table 31, are based on a moving target of conventional plant costs. Line 3 presents projections of these decreasing investment costs of coal-fired plants for average construction conditions. The resulting range in total generating cost of power from nuclear plants (at the busbar), based on the factors included in table 31 are given in line 3 of table 32. The computation assumes an 80 percent plant factor for nuclear projects.

TABLE 32

Projected Range in Nuclear Generation Costs

1. Year plant placed in service	1967	1970	1975	1980
2. Nominal plant output—kilowatts	300, 000	500, 000	1, 000, 000	1, 200, 000
3. Range in generating cost (at busbar) for nuclear plants—mills/kwh	5. 4–6. 0	4. 3–5. 0	3. 5–4. 1	3. 2–3. 8

Other less well developed nuclear plant concepts may eventually achieve better economy than the water reactors considered in table 31. For example, reactors using heavy water as a moderator (which enables neutrons to be used more effectively for continuing the fission chain reaction—and which might be used with natural uranium or with fuels having lower enrichment and lower costs) may be able to make better use of the energy potential of nuclear materials. Other arrangements, such as the "seed and blanket" type, seek to achieve higher yields by converting larger portions of fertile materials such as U^{238} into plutonium, or thorium into U^{233}, and thereby obtain higher conversion ratios.

Estimated Nuclear Capacity Installations by 1980

The rate of installation of new nuclear generating plant capacity is dependent not only upon the realization of projected declines in nuclear plant and fuel costs, but also upon the attitudes of utility management. It seems likely that utility management will be alert to use proven types of nuclear plants, but will be reluctant to undertake the construction of unproven types. Even for proven types, a 4-year or longer design and construction period is needed for the larger plants, and this period must be followed by several years of operation before projected costs are achieved. Therefore, any decision to proceed with a nuclear plant must be in anticipation of the low cost results to be achieved some eight years in the future with due allowance for higher costs in the first several years of operation.

As a result of its studies which were completed prior to recent lower price quotations, the Generating Stations Special Technical Committee estimated that 40 million kilowatts of nuclear capacity would be installed in the contiguous United States by 1980. In recognition of current rapid nuclear power developments and the lower cost estimates presented above, the Federal Power Commission staff estimates that nuclear power installations by 1980 will aggregate nearly 70 million kilowatts. The general location of this capacity is discussed in chapter 15.

Nuclear Fuel Reserves

While estimates of uranium reserves in the United States are revised periodically, it is generally agreed that those minable at reasonable cost appear to be relatively limited. Reserve estimates which include allowances for "undiscovered" resources must involve a high degree of uncertainty. However, in practice when a substantial market is developed for a resource, additional supplies usually are discovered. As indicated in table 33, the latest estimate of total known and undiscovered uranium resources minable at $5 to $10 a pound of uranium oxide, ($U_3\ O_8$) is about 900,000 tons of metal.

The significance of these reserve estimates in relation to present commercial reactors may be judged from a rough analysis. A 1,000-megawatt water moderated nuclear plant will require an initial fuel charge of about 150 metric tons of uranium enriched to perhaps 2.5 percent U^{235}. Since the content of U^{235} in natural uranium is only 0.7 percent and also because only about two-thirds of the U^{235} content of the natural uranium can be extracted economically, some 800 metric tons of uranium must be mined in all to provide the initial enriched fuel charge.

TABLE 33
Tons of Nuclear Materials Obtainable at Various Costs [1]

URANIUM RESOURCES OF THE UNITED STATES

Present cost in dollars per pound of U_3O_8 with present recovery technology	Approximate known deposits (tons of metal)	Unappraised and undiscovered resources (tons of metal)
$5–$10	142, 000	770, 000
$10–$30	140, 000	500, 000
$30–$100	12, 300, 000	20, 000, 000
$100–$500	No Est.	4, 000, 000, 000

THORIUM RESOURCES OF THE UNITED STATES

Present cost in dollars per pound of ThO_2 with present recovery technology	Approximate known deposits (tons of metal)	Unappraised and undiscovered resources (tons of metal)
$5–$10	100, 000	800, 000
$10–$30	100, 000	1, 700, 000
$30–$100	No Est.	30, 000, 000
$100–$500	No Est.	6, 000, 000, 000

The fissioning of 1 metric ton of U^{235} will release enough heat to generate about 7 billion kilowatt-hours, or approximately the electrical output of 1,000-megawatts of nuclear plant capacity for a year at 80 percent plant factor. Thus keeping the 1,000-megawatt nuclear plant in operation apparently would require mining some 200 metric tons of natural uranium a year to provide the U^{235} consumed. This calculation overstates requirements, as the water reactor postulated can generate new fuel equal to perhaps half of that destroyed, reducing the natural uranium requirement to about 100 metric tons a year.

On the basis of these figures a 1,000-megawatt nuclear plant operated for 35 years would require the mining of some 4,000 metric tons of natural uranium, or about a half of 1 percent of the total uranium reserves thought to be minable at $5 to $10 per pound. By about 1980, perhaps 10 percent of the estimated total $5–$10 a pound reserves will have been used, and annual rates of consumption will be approaching 1 percent. The plants then in operation would require some 30–40 percent of those reserves for their continued operation through their prospective future lives.

Some very general conclusions may be drawn from these rough estimates:

1. Present estimates of low cost U.S. uranium reserves are adequate to support lifetime operation of nuclear plants based on present ordinary water reactors or other reactor types of low efficiency well into the 1980's.
2. A large and expanding nuclear industry will someday require the development of reactor types that can produce more fuel than they consume, i.e., "breeders." In the meantime, reactors having higher "conversion ratios" than present water reactors, that is, reactors which can regenerate fuel in larger proportions to that consumed, are needed to extend the usefulness of uranium reserves. To illustrate, a reactor which could produce new fuel at the rate of ¾ rather than ½ that consumed would require mining only about half as much natural uranium.
3. So long as prospects remain good that economical breeders can be developed in the reasonable future, there should be little inhibition in the development of nuclear power on the scale predicted in this report to 1980.

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[1] Based upon recent estimates in staff papers for the Interdepartmental Energy Study, using mining and processing costs estimated by AEC for $5 to $10 per pound sources, and by U.S. Geological Survey for various other types of deposits.

4. While the discovery of new reserves and the development of high ratio converters would considerably extend this suggested time scale, it does not obviate the eventual need for breeders.

In considering the rate at which the water reactors use nuclear fuel, it should be kept in mind that even though these reactors do not use fuel as effectively as might be desired, almost all the unused material may be recovered if the fuel is reprocessed and used as feed for breeder reactors when they are developed. At present, reprocessing is difficult and expensive because it involves working with highly radioactive materials on a small scale.

Development of High Conversion Ratio Reactors and Breeders

The AEC and the industry are now engaged in research and development on "plutonium recycle," and on higher conversion ratio reactors which can help provide the technology needed for development of increased energy yields and breeder reactors. In December 1963, the AEC announced a comprehensive program of breeder reactor development with the objective of placing in operation a commercial, economically competitive 1,000-megawatt plant by 1989. Four conceptual core design studies of fast breeder reactors were under way at the end of 1963, and start-up of a 200-megawatt prototype is tentatively scheduled for 1973. Several demonstration plants in the 400- to 800-megawatt range are expected to be built in the early 1980's. This program holds out the hope that energy yields from a given quantity of nuclear material may eventually be increased so greatly that they would permit economic use of the full potential of nuclear ores.

Nuclear Heat for Desalting Sea Water

The problem of providing adequate water supplies for certain areas, primarily in the western United States, has been growing steadily, and the concern of local and Federal authorities has spurred the development of several possible desalting schemes for sea water and high-mineral content inland water supplies. Evaporation is one of the obvious methods being explored, but normal fuel costs present a severe handicap.

Workers in AEC's Reactor Development Program have contended, however, that both unit capital costs and unit fuel costs should continue to decline for nuclear plants 10 to 50 times the size of those generally considered large today, and that the expected very-low-cost energy from such reactors possibly could provide an economical source of heat for large water evaporating plants. The heat could be supplied either directly from the reactors or as low pressure exhaust steam from steam turbines driving electric generators.

Of course conventional steam plants also offer opportunities for use in combination with water evaporating plants. We discuss nuclear possibilities here only because the studies to date have been made in connection with nuclear plants.

The report of an interagency task group appointed by the Director, Office of Science and Technology,[7] which made a preliminary analysis of such long-range opportunities expresses the conclusion that nuclear power costs could be reduced appreciably below the best fossil fuel-fired plant costs if the nuclear plant could be built with perhaps 8,000–10,000 megawatts of capacity. Such a plant would include several integrated reactors and generating units.

Obviously no single power system in the United States could now contemplate the installation of such a plant, which in itself would be as large as any single major system in the country excepting TVA. But groups of systems, by pooling their generating plant additions, might share responsibility for such a power supply. Such plants, including the desalination portions, are only in the early conceptual stages and cost estimates must be regarded as highly conjectural. Of course, the foregoing approach would be justified only if the plan proved to be more economical than alternatives after considering required transmission, necessary reserves and other factors. Nevertheless, the meshing of water needs and power needs—whether supplied by nuclear or conventional means—at appropriate sites may offer opportunities for both lower cost demineralized water and lower cost electric energy.

Summary and Conclusions

Nuclear power technology has shown rapid advances in the last decade. Plants now in the planning stage are expected to be competitive with conventional steam-electric generation in many areas of the country in the next decade. Anticipated reductions in the cost of fabricating and reprocessing nuclear fuels together with lower construction costs should further improve its competitive position.

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[7] An Assessment of Large Nuclear Power Sea Water Distillation Plants, March 1964—Office of Science and Technology.

By 1980 it is estimated that nuclear generation will be competitive in nearly all parts of the country. The 65 to 70 million kilowatts of nuclear capacity projected for 1980 would move nuclear power from an experimental stage to a major source of electric power supply. Moreover it may approach the limit of the capacity that can be designed, manufactured and installed between now and then.

CHAPTER 6

HYDROELECTRIC POWER RESOURCES

Historically, hydroelectric and steam-electric plants have constituted the two principal sources of the Nation's electric energy production. Thirty years ago hydroelectric power plants provided about 30 percent of the generating capacity and 40 percent of the energy supplied by electric systems. Since that time, the percentage of power supplied from this resource has declined, as the demand for power in many parts of the country has outstripped the local availability of economical hydroelectric sites. At present, hydroelectric plants provide 19 percent of the capacity and energy produced. Studies show that this downward trend will continue and that by 1980 conventional [1] hydroelectric developments will supply about 15 percent of the capacity and 13 percent of the energy.

Nevertheless, hydroelectric capacity is expected to double from 40 million kilowatts to 78 million kilowatts by 1980, and to continue to be a major source of power supply in the Pacific Northwest. The hydro potential for the 48 contiguous States is estimated at 134 million kilowatts of capacity. In addition, Alaska could develop up to 20 million kilowatts, and power imports from Canada could add an additional 7 million kilowatts of capacity.

In 1963, privately owned hydro plant capacity totalled 14.2 million kilowatts, and non-Federal public groups owned 8.4 million kilowatts. Most of the 16.8 million kilowatts of capacity under Federal ownership is part of multipurpose hydro developments.

Characteristics of Hydroelectric Power

Hydroelectric power is unique among basic electric energy sources in that it does not require fuel for generation. The recurring cycles of rainfall, runoff, evaporation and transpiration make hydroelectric power a renewable energy resource.

Hydroelectric plants have several important advantages over thermal plants. They neither consume water, nor do they heat the water of rivers and streams as thermal plants do with the possibility of causing thermal pollution; and they do not contribute to air pollution. The maintenance costs of hydroelectric plants are relatively low, and in many instances the plants can be designed for automatic or remote control operation. They have long life, low depreciation expenses, and relatively predictable costs, inasmuch as fixed charges are a much larger part and current operating expenses a much smaller share of total costs than in the cases of fuel-burning plants. The generating units are more reliable than steam-electric units because they operate at relatively low speeds and the turbines are not subjected to temperature stresses. A unit is normally out of service about 2 days per year because of forced outages and about 1 week for scheduled maintenance. This outage rate of approximately 3 percent is about one-fourth that for modern steam-electric units. However, the availability of hydroelectric capacity may, in some cases, be restricted at times of high streamflow conditions or due to the requirements of other water uses.

In many cases the development of hydroelectric power provides such associated benefits as recreation, water supply, fish and wildlife enhancement, flood control, and cooling water for thermal-electric and industrial plants. Many mutiple-purpose projects would not be economically justified without the inclusion of power as one of the project purposes. The favorable characteristics of hydroelectric power and the frequent multiple use benefits associated with its development provide strong incentives for utilizing the remaining potential of our water power resources that can be developed economically.

Developed and Undeveloped Hydroelectric Potential

The Federal Power Commission maintains an inventory of the water power resources of the country. Data on individual developed and undeveloped projects are compiled annually and published at intervals of 3 to 4 years.[2]

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[1] Pumped storage developments, which are constructed specifically to provide peaking capacity, are discussed in chapter 7, Peaking Power.

The estimated hydroelectric power potential of the 48 contiguous States, as of January 1, 1964, was 134 million kilowatts of capacity, capable of producing an average of about 500 billion kilowatt-hours of electric energy annually, or about one-half of the total present production by all types of generating equipment.

About 40 million kilowatts, or 30 percent of the total potential hydroelectric capacity, has been developed. This capacity generates an average of 175 billion kilowatt-hours of electric energy per year. The existing capacity is in more than 1,500 plants. Of these, 159 are plants having installed capacities of 50,000 kilowatts or more. Five plants have installations in excess of 1,000 megawatts. These are Niagara Falls on the Niagara River (1,954 mw [3]); Hoover on the Colorado River (1,340 mw); and The Dalles (1,119 mw), Chief Joseph (1,024 mw), and Grand Coulee (1,944 mw), all on the Columbia River.

The undeveloped hydroelectric power potential is estimated to be about 94 million kilowatts with a potential average annual generation of 325 billion kilowatt-hours. These figures include projects under construction and those being planned for construction, as well as projects selected from various river basin investigations. The largest amount of capacity, both developed and undeveloped, is in the Pacific Northwest which includes the large potential of the Columbia River Basin.

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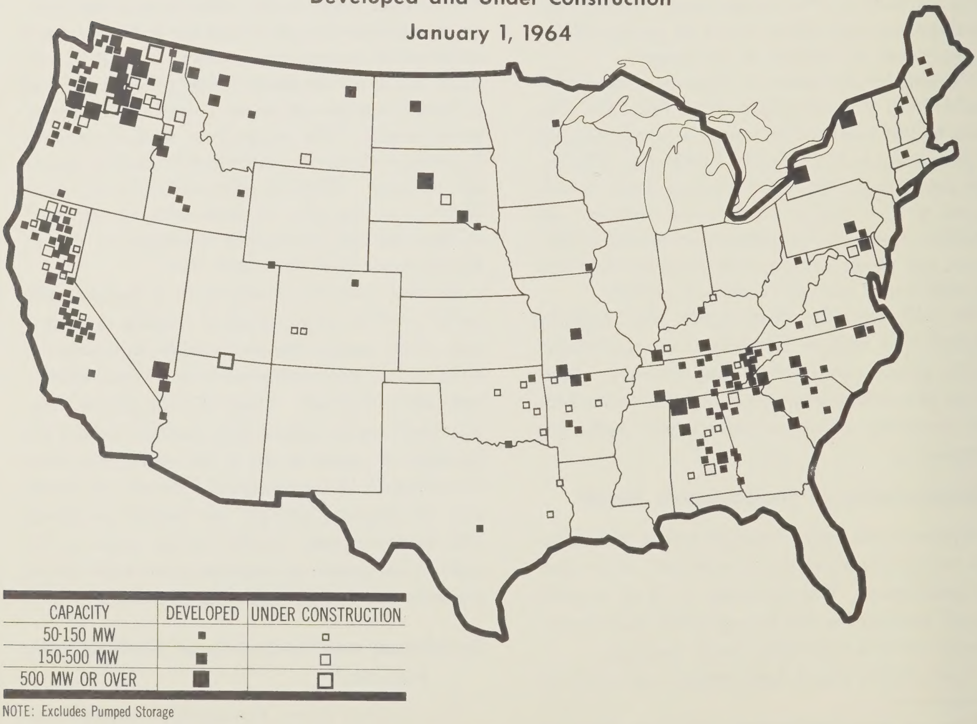
[2] Hydroelectric Power Resources of the United States, Developed and Undeveloped, Federal Power Commission.

[3] Excludes 240 megawatts in reversible units which have the capability of both pumping water to a pumped storage reservoir and alternately generating power by using the return of this water through the units.

PRINCIPAL HYDROELECTRIC PROJECTS

Developed and Under Construction

January 1, 1964



CAPACITY	DEVELOPED	UNDER CONSTRUCTION
50-150 MW	▪	▫
150-500 MW	■	□
500 MW OR OVER	■	□

NOTE: Excludes Pumped Storage

6-2

FIGURE 52

Approximately 10.9 million kilowatts of the undeveloped potential capacity is in projects which are now under construction. Such projects include: Smith Mountain on the Roanoke River (300 mw [4]); Big Bend on the Missouri River (468 mw); Glen Canyon on the Colorado River (900 mw); Oroville on the Feather River (351 mw [5]); John Day (1,350 mw) and Wells (494 mw) on the Columbia River; and Hells Canyon (370 mw), Little Goose (405 mw), and Lower Monumental (405 mw), all on the Snake River.

Figure 52 shows the locations of hydroelectric power projects [6] both developed and under construction, having installed capacities of 50 megawatts or more. These projects are listed by coordination study areas in table 34.

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[4] Excludes 132 megawatts of capacity in reversible units.

[5] Excludes 261 megawatts of capacity in reversible units.

[6] Excludes one industrially owned plant (102 megawatts) of this size.

TABLE 34

Hydroelectric Capacity Existing and Under Construction as of Jan. 1, 1964

(Listed Projects Have Installations of 50 mw or More)

Coordination study area	Name of project	River	State	Installed capacity, mw: Existing	Installed capacity, mw: Under construction
A—New England	Wyman	Kennebec	Maine	72	....
	Harris	Kennebec	Maine	75	....
	Cabot	Connecticut	Massachusetts	51	....
	Comerford	Connecticut	New Hampshire	140	....
	S. C. Moore	Connecticut	New Hampshire	141	....
B—New York	Robert Moses	St. Lawrence	New York	912	....
	Niagara	Niagara	New York	R1,954	....
C—Pennsylvania-New Jersey-Maryland.	Conowingo	Susquehanna	Maryland	252	240
	Holtwood	Susquehanna	Pennsylvania	107	....
	Safe Harbor	Susquehanna	Pennsylvania	230	....
D—Ohio Valley	Claytor	New	Virginia	75	....
	Lake Lynn	Cheat	West Virginia	50	....
	Markland	Ohio	Indiana	....	81
	Barkley	Cumberland	Kentucky	....	130
	Smith Mountain	Roanoke	Virginia	....	R300
	Ohio Falls	Ohio	Kentucky	80	....
E—Carolinas-Virginia	Roanoke Rapids	Roanoke	North Carolina	100	....
	Gaston	Roanoke	North Carolina	177	....
	John H. Kerr	Roanoke	Virginia	204	....
	Tillery	Yadkin	North Carolina	84	....
	Pinopolis	Santee Cooper	South Carolina	132	....
	Wateree	Wateree	South Carolna	56	....
	Wylie	Catawba	South Carolina	60	....
	Mountain Island	Catawba	North Carolina	60	....
	Cowans Ford	Catawba	North Carolina	262	....
	Saluda	Saluda	South Carolina	130	....
	Clark Hill	Savannah	South Carolina	280	....
	Walters	Pigeon	North Carolina	108	....
F—Tennessee Valley	Kentucky	Tennessee	Kentucky	160	....
	Pickwick Landing	Tennessee	Tennessee	216	....
	Wilson	Tennessee	Alabama	598	....
	Wheeler	Tennessee	Alabama	356	....
	Guntersville	Tennessee	Alabama	97	....

R—Denotes plant with reversible capacity in addition to that shown. See table 41.

TABLE 34—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw	
				Existing	Under construction
F—Tennessee Valley—Continued	Hales Bar	Tennessee	Tennessee	99	
	Chickamauga	Tennessee	Tennessee	108	
	Apalachia	Hiwassee	Tennessee	75	
	Hiwassee	Hiwassee	North Carolina	57	
	Watts Bar	Tennessee	Tennessee	150	
	Melton Hill	Clinch	Tennessee		72
	Norris	Clinch	Tennessee	100	
	Chilhowee	Little Tennessee	Tennessee	50	
	Calderwood	Little Tennessee	Tennessee	121	
	Cheoah	Little Tennessee	North Carolina	110	
	Fontana	Little Tennessee	North Carolina	202	
	Fort Loudoun	Tennessee	Tennessee	128	
	Douglas	French Broad	Tennessee	112	
	Cherokee	Holston	Tennessee	120	
	Watauga	Watauga	Tennessee	50	
	Boone	South Fork Holston	Tennessee	75	
	Old Hickory	Cumberland	Tennessee	100	
	Center Hill	Caney Fork	Tennessee	135	
	Cordell Hull	Cumberland	Tennessee		100
	Dale Hollow	Obey	Tennessee	54	
	Wolf Creek	Cumberland	Kentucky	270	
G—Southeastern	Hartwell	Savannah	Georgia	264	
	Tallulah Falls	Tallulah	Georgia	72	
	Walter F. George	Chattahoochee	Georgia	130	
	Oliver	Chattahoochee	Georgia	60	
	Bartletts Ferry	Chattahoochee	Georgia	65	
	Buford	Chattahoochee	Georgia	86	
	Lewis Smith	Sipsey Fork	Alabama	157	
	Millers Ferry	Alabama	Alabama		76
	Thurlow	Tallapoosa	Alabama	50	
	Martin Dam	Tallapoosa	Alabama	154	
	Jordan No. 1	Coosa	Alabama	100	
	Jordan No. 2	Coosa	Alabama		150
	Mitchell	Coosa	Alabama	72	
	Lay Dam	Coosa	Alabama	81	
	Logan Martin	Coosa	Alabama		128
	Weiss	Coosa	Alabama	87	
	Lock and Dam No. 3	Coosa	Alabama		73
	Allatoona	Etowah	Georgia	74	
	Carters Dam	Coosawattee	Georgia		250
H—Lower Michigan	None				
I—North Central	Thomson	St. Louis	Minnessota	67	
	Keokuk	Mississippi	Iowa	124	
	Osage	Osage	Missouri	172	
J—Texas	Mansfield	Colorado	Texas	67	
	Denison	Red	Texas	70	
K—Middle South	Carpenter	Ouachita	Arkansas	56	
	Blakely Mountain	Ouachita	Arkansas	75	
	Broken Bow	Mountain Fork	Oklahoma		100
	Dardanelle	Arkansas	Arkansas		124
	Robert S. Kerr	Arkansas	Oklahoma		110
	Eufaula	Canadian	Oklahoma		90
	Markham Ferry	Grand	Oklahoma		110

TABLE 34—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw	
				Existing	Under construction
K—Middle South—Con.	Pensacola	Grand	Oklahoma	86	
	Keystone	Arkansas	Oklahoma		70
	Greers Ferry	Little Red	Arkansas		96
	Norfork	North Fork	Arkansas	70	
	Bull Shoals	White	Arkansas	340	
	Table Rock	White	Missouri	200	
	Beaver	White	Arkansas		112
	Toledo Bend	Sabine	Texas		80
	Sam Rayburn	Angelina	Texas		52
L—Upper Missouri Basin.	Gavins Point	Missouri	Nebraska	100	
	Fort Randall	Missouri	South Dakota	320	
	Big Bend	Missouri	South Dakota		468
	Oahe	Missouri	South Dakota	595	
	Garrison	Missouri	North Dakota	400	
	Fort Peck	Missouri	Montana	165	
M—New Mexico and Panhandle	None				
N—Southwest	Folsom	American	California	162	
	Ralston	Middle Fork American.	California		79
	Middle Fork	Middle Fork American.	California		110
	White Rock	South Fork American.	California		200
	Camino	Silver Creek	California	71	
	Jaybird	Silver Creek	California	133	
	Oroville	Feather	California		R351
	Woodleaf	South Fork Feather	California	52	
	Poe	North Fork Feather	California	124	
	Cresta	North Fork Feather	California	67	
	Rock Creek	North Fork Feather	California	113	
	Bucks Creek	North Fork Feather	California	66	
	Belden	North Fork Feather	California		117
	Caribou No. 1 and 2	North Fork Feather	California	184	
	Clear Creek	Clear Creek	California	134	
	Spring Creek	Spring Creek	California		150
	Keswick	Sacramento	California	75	
	Shasta	Sacramento	California	375	
	McCloud-Pit	Pit	California		156
	Pit No. 7	Pit	California		104
	Pit No. 6	Pit	California		79
	Pit No. 5	Pit	California	128	
	Pit No. 4	Pit	California	90	
	Pit No. 3	Pit	California	74	
	Pit No. 1	Pit	California	56	
	New Electra	Mokelumne	California	89	
	Tiger Creek	North Fork Mokelumne.	California	51	
	Stanislaus (New)	Stanislaus	California	82	
	Donnells	Middle Fork Stanislaus.	California	54	
	Moccasin Creek	Moccasin Creek	California	70	
	Cherry Creek	Cherry Creek	California	135	
	Canyon	Tuolumne	California		67

TABLE 34—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw: Existing	Installed capacity, mw: Under construction
N—Southwest—Con.	Big Creek No. 4	San Joaquin	California	84	
	Big Creek No. 3	San Joaquin	California	106	
	Big Creek No. 8	San Joaquin	California	58	
	Big Creek No. 2A	Big Creek	California	80	
	Big Creek No. 2	Big Creek	California	57	
	Big Creek No. 1	Big Creek	California	67	
	Mammoth Pool	San Joaquin	California	129	
	Balch	North Fork Kings	California	128	
	Haas	North Fork Kings	California	135	
	S. Francisquito	Los Angeles Aqueduct	California	58	
	Trinity	Trinity	California		100
	Parker	Colorado	California	120	
	Davis	Colorado	Arizona	225	
	Hoover	Colorado	Arizona-Nevada	1,340	
	Glen Canyon	Colorado	Arizona		900
O—Colorado-Wyoming	Flatiron No. 1 and No. 2.	Colorado Big-Thompson Diversion.	Colorado	63	
	Blue Mesa	Gunnison	Colorado		60
	Morrow Point	Gunnison	Colorado		120
	Yellowtail	Bighorn	Montana		250
P—Northwest	Lower Baker	Baker	Washington	103	
	Upper Baker	Baker	Washington	94	
	Gorge	Skagit	Washington	134	
	Diablo	Skagit	Washington	120	
	Ross	Skagit	Washington	360	
	White River	White	Washington	70	
	La Grande	Nisqually	Washington	64	
	Alder	Nisqually	Washington	50	
	Cushman No. 2	North Fork Snohomish	Washington	81	
	Merwin	Lewis	Washington	135	
	Mayfield	Cowlitz	Washington	120	
	Yale	Lewis	Washington	108	
	Swift No. 2	Lewis	Washington	70	
	Swift No. 1	Lewis	Washington	204	
	Oak Grove	Clackamas	Oregon	51	
	Detroit	North Santiam	Oregon	118	
	Green Peter	Middle Santiam	Oregon		100
	Lookout Point	Middle Fork Willamette.	Oregon	135	
	Carmen Smith	McKenzie	Oregon	80	
	Bonneville	Columbia	Oregon	518	
	The Dalles	Columbia	Washington	1,119	
	Pelton	Deschutes	Oregon	108	
	Round Butte	Deschutes	Oregon		247
	John Day	Columbia	Washington		1,350
	McNary	Columbia	Oregon	980	
	Ice Harbor	Snake	Washington	270	
	Lower Monumental	Snake	Washington		405
	Little Goose	Snake	Washington		405
	Hells Canyon	Snake	Oregon-Idaho		370
	Oxbow	Snake	Oregon	190	
	Brownlee	Snake	Idaho	360	
	C. J. Strike	Snake	Idaho	82	

TABLE 34—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw	
				Existing	Under construction
P—Northwest—Con.	Bliss	Snake	Idaho	75	
	Lower Salmon	Snake	Idaho	60	
	Palisades	Snake	Idaho	114	
	Dworshak (Bruces Eddy).	North Fork Clearwater.	Idaho		300
	Priest Rapids	Columbia	Washington	788	
	Wanapum	Columbia	Washington	748	83
	Rock Island	Columbia	Washington	212	
	Rocky Reach	Columbia	Washington	711	
	Wells	Columbia	Washington		494
	Chief Joseph	Columbia	Washington	1, 024	
	Grand Coulee	Columbia	Washington	1, 944	
	Long Lake	Spokane	Washington	70	
	Box Canyon	Pend Oreille	Washington	60	
	Boundary	Pend Oreille	Washington		551
	Cabinet Gorge	Clark Fork	Idaho	200	
	Noxon Rapids	Clark Fork	Montana	282	
	Kerr	Flathead	Montana	168	
	Hungry Horse	South Fork Flathead	Montana	285	
	Flaming Gorge	Green	Utah	72	
	Canyon Ferry	Missouri	Montana	50	
	John C. Boyle	Klamath	Oregon	79	
Subtotal				31, 394	10, 160
Installations of less than 50 mw				8, 032	723
Total				39, 426	10, 883
Grand total (existing and under construction)					50, 309

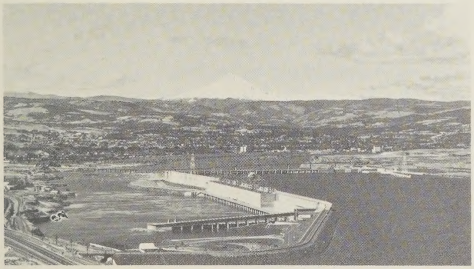

FIGURE 53 *The Dalles Dam on the Columbia River, like all mainstem dams below Chief Joseph Dam, is equipped with fish facilities to accommodate the large runs of anadromous salmon and trout. One of the two fish ladders of the project is shown in the center foreground in front of the power plant. The spillway section is in the center of the photograph and the navigation lock towards the extreme right. Snow covered Mt. Hood looms in the background.*

Patterns of Hydroelectric Development

The patterns of developing the rivers of the country for hydroelectric power production and other water uses have evolved over a period of several decades. The earliest hydroelectric developments were single-purpose projects. However, an increasing realization of the necessity to derive maximum benefits from the water and related land resources made inevitable the development of multiple-purpose projects.

Federal regulations affecting water power development began late in the last century. Beginning in 1884 the Congress enacted a number of special statutes authorizing power developments by private interests on navigable streams. These grants of authority contained few conditions and some were in perpetuity. The General Dam Acts of 1906 and 1910 brought some measure of uniformity in the terms and conditions to be imposed by the Secretary of War in connection with non-Federal development of hydroelectric power on streams subject to Federal jurisdiction, including a limitation of 50 years in the terms of the permits.

During the 1900–20 period several temporary commissions[7] created by the President or the Congress studied problems of water resources development and in their reports discussed the multiple-purpose aspects of such undertakings. Spurred by the conservation movement, there were sharp conflicts of views as to the proper means of developing hydroelectric power on navigable streams and on lands owned by the United States. Highlighting the need for a solution of this problem were several Presidential vetoes[8] of bills granting broad rights for non-Federal development, without assurance of comprehensive development or protection of the public interest.

In 1920 Congress passed the Federal Water Power Act, regularizing and facilitating Federal permission for non-Federal development of hydroelectric power under a licensing system. Licenses were to be issued by the Federal Power Commission which was created by the act. In 1935 this act became Part I of the Federal Power Act.

The first Federal developments of hydroelectric power were made at reclamation projects pursuant to the Reclamation Act of 1902, as supplemented in 1906. During the World War I period the development of hydroelectric power for defense purposes was undertaken by the Federal Government on the Tennessee River near Muscle Shoals, Ala., to provide power for a munitions complex and a navigation facility for a stretch of the Tennessee River which constituted a navigation bottleneck. This development at Wilson Dam was not completed before the war ended, but construction continued and the dam was finished in 1925.

Congressional authorization of the Boulder Canyon (Hoover Dam) project on the Colorado River, Arizona and Nevada, in 1928 marked the initial undertaking by the Federal Government of a large-scale project designed for peacetime multiple-purpose use on a major river. The Secretary of the Interior was authorized to construct and operate the project for flood control, navigation, reclamation, and other purposes, and to include power as a means of making the project a self-supporting and financially solvent undertaking.

Under the National Industrial Recovery Act of 1933 and in the interest of relieving unemployment, a number of large multiple-purpose projects were undertaken by various agencies of the Federal Government with funds allocated to them for this purpose by the President. Included among such projects were Fort Peck on the Missouri River in Montana; Bonneville on the lower Columbia in Washington and Oregon; and Grand Coulee on the upper Columbia River in Washington. These projects subsequently received Congressional authorization and were completed with funds appropriated by the Congress.

The Tennessee Valley Authority Act of 1933 created TVA in the form of a Federal corporation for purposes of acquiring and operating the Government's Muscle Shoals properties in the interest of national defense, for agricultural and industrial development, for the improvement of navigation on the Tennessee River, and for the control of floods in the Tennessee and Mississippi River Basins. TVA thereupon operated Wilson Dam and built numerous other projects including the multipurpose hydroelectric power plants which have made the Tennessee River our most fully developed waterway. It also acquired the generating plants and transmission facilities of utility companies in the area and built steam-electric plants and transmission lines, which are integrated into a single power network with its hydroelectric plants to meet the power requirements of the TVA service area.

By the 1936 Flood Control Act and subsequent Flood Control and River and Harbor Acts, the Congress authorized numerous river development projects to be constructed by the Corps of Engineers, Department of the Army, for flood control, navigation, and other purposes including power. Among the early projects constructed were Denison on the Red River in Oklahoma and Texas; Norfork and Bull Shoals in the White River Basin in Arkansas and Missouri; Clark Hill on the Savannah River in Georgia and South Carolina; and John H. Kerr on the Roanoke River in Virginia.

The Reclamation Project Act of 1939 recognized multiple-use possibilities. Under that and other authorizations, the Bureau of Reclamation, De-

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[7] Inland Waterways Commission (1907), National Conservation Commission (1908), National Waterways Commission (1909), Waterways Commission (1917).

[8] Rainy River (1908), James River (1909), White River (1912), and Coosa River (1912).

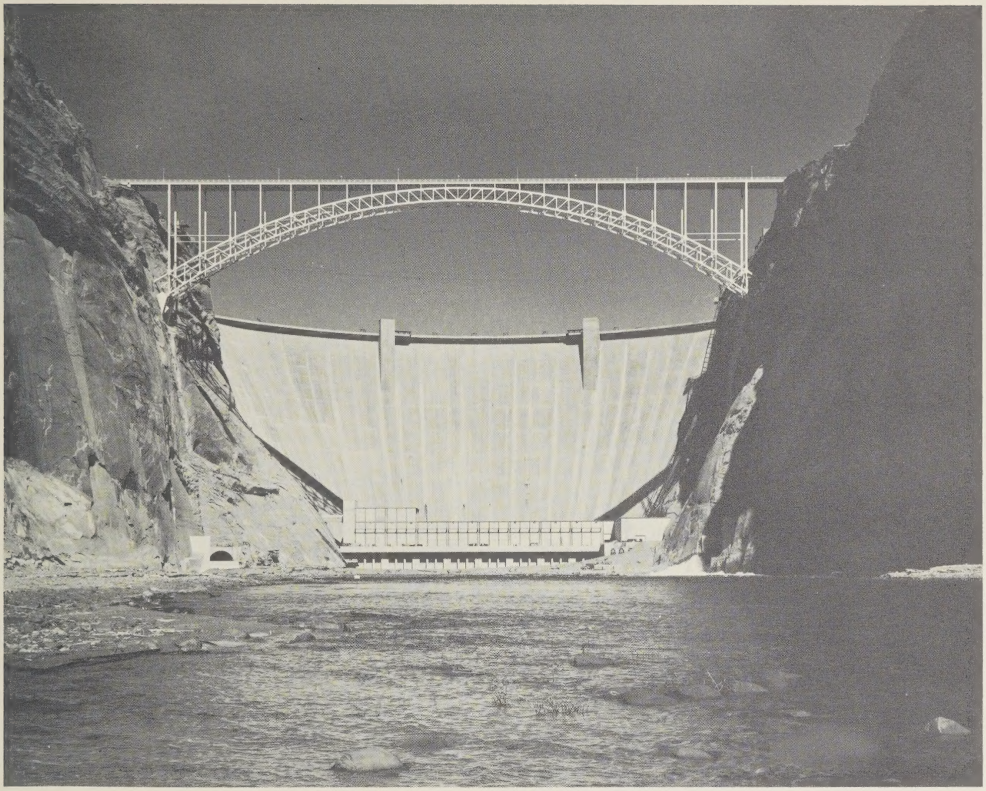


FIGURE 54 *The nearly completed Glen Canyon Dam of the Bureau of Reclamation, situated on the Colorado River at the lower end of the Upper Colorado Basin, will provide regulation of flow in accordance with the interstate compact. Its power plant has a generating capacity of 900,000 kilowatts.*

partment of the Interior, has investigated and undertaken a number of multiple-purpose river development programs in the Western States. Among the important projects are the Columbia Basin Project, including Grand Coulee Dam, in Washington; the Central Valley Project in California, including Shasta Dam; and various developments in the Missouri and Colorado River Basins.

Hydroelectric Development Under Licenses

Under provisions of the Federal Power Act, the Commission issues licenses for definite terms not in excess of 50 years to individuals, corporations, States, and municipalities, authorizing the construction, operation, and maintenance of hydroelectric projects on streams over which Congress has jurisdiction, including proprietary jurisdiction because Government lands are involved. It may also issue licenses to those non-Federal interests for the purpose of utilizing the surplus water or water power from a Government dam.

As of January 1, 1964, there were 279 licenses in effect covering major projects having some 17.7 million kilowatts of existing installed capacity and 25.9 million kilowatts of ultimate capacity. Approximately 4.7 million kilowatts of capacity are currently being constructed in new projects under license. The existing capacity under license represents 76 percent of all conventional non-Federal hydroelectric capacity in the United States. Most of the remaining 5.6 million kilowatts of non-Federal hydroelectric capacity is in relatively small

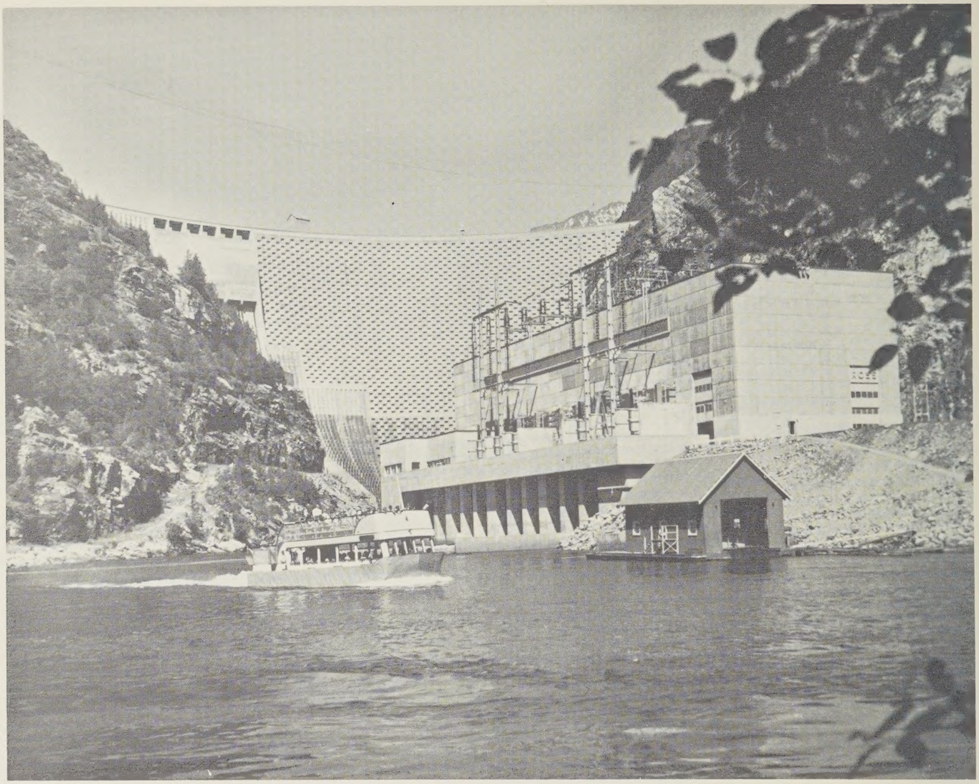


FIGURE 55 *Seattle City Light's 360,000 kilowatt Ross Powerhouse with 540-foot-high Ross Dam in the background, is the key structure of municipality's Skagit Project. Arching 1300 feet from wall to wall of the river canyon, it impounds 1,400,000 acre-feet of water in a lake 25 miles long, etending into Canada. The waffle-like construction of the face of the dam is designed for future enlarging of the structure. If the dam is raised another 125 feet as contemplated, additional concrete will be interlocked with the 5-foot square depressions to thicken the dam.*

projects, and applications for license are pending for 124 of these constructed projects. Some of the presently unlicensed capacity is probably subject to FPC licensing jurisdiction. Those unlicensed developments which are subject to FPC jurisdiction have remained unlicensed for several reasons, including changing standards of jurisdiction as well as staff limitations that hinder efforts to reach numerous, scattered small developments. The Commission in the past 3 years has developed a program for bringing these projects under license and has contacted the owners of all the larger projects, involving 193 owners of some 500 developments larger than 1,500-kilowatt capacity. It is anticipated that, as a result of this effort, a substantial part of the total unlicensed capacity will be licensed within the near future.

An important conservation requirement of the Federal Power Act is the requirement that a project to be licensed must, in the judgment of the Commission, be best adapted to a comprehensive basin plan for all useful purposes. In addition to standard provisions requiring compliance with rules prescribed for the protection of life, health, and property, licenses may contain special provisions in the interest of flood control, navigation, public

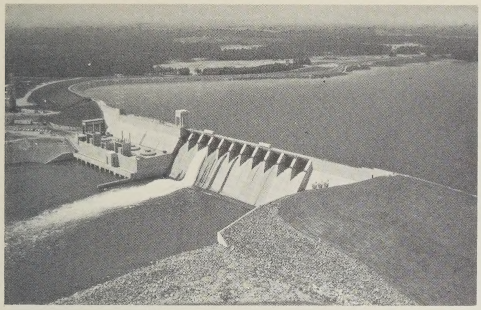


FIGURE 56 *Cowans Ford hydroelectric installation on the Catawba River in North Carolina is a 262,000 kilowatt plant owned by the Duke Power Company and opperated under license from the Federal Power Commission.*

health, recreation, preservation of scenic beauty, or protection of fish and wildlife. The Commission amended its regulations recently to require each applicant for a license to file a proposed plan for full public utilization of the project waters and adjacent project lands for recreational purposes. It also has under consideration the promulgation of rules relating to the reasonable use of project works for domestic and industrial water supplies, pumped storage generation, steam-electric cooling water supplies, irrigation, and similar purposes. Thus, the Federal Power Commission, through its licensing activities for non-Federal projects, has encompassed the full scope of multiple-purpose planning. The FPC hydroelectric license is a comprehensive document which ties together the many facets of comprehensive development. In the authority to prescribe license conditions, Congress placed in the Commission's hands a flexible and effective tool for the best and most orderly development of national water resources in the face of evolving needs.

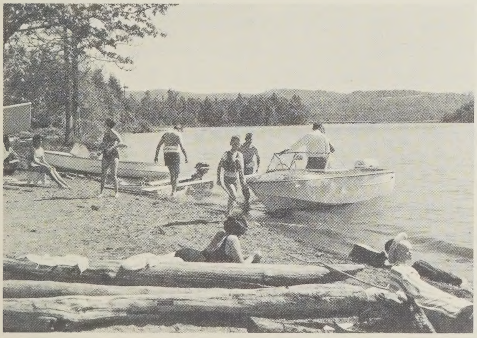


FIGURE 57 *Lake at Tacoma's Mayfield project attracts boaters, skiers, fishermen, picnickers and outdoorsmen from miles around.*

FIGURE 58 *Huntington Lake of Southern California Edison's Big Creek Project is well suited for recreation and attracts thousands of visitors each year.*

Hydroelectric Development by the Federal Government

In carrying out their programs of multiple-purpose river development, the Federal agencies have installed 16.8 million kilowatts of hydroelectric capacity which constitutes 42 percent of the total existing capacity. Some 6.1 million kilowatts of capacity are now under construction. The distribution of capacity among the three principal Federal agencies which construct and operate hydroelectric projects is shown in table 35.

The development of the Tennessee River Basin by the TVA provides an excellent example of essentially complete utilization under unified control of the available water resources of a basin for multiple-purpose uses. As shown in figure 60 the major structures include reservoir projects in the headwater tributaries to provide flood control and conservation storage and consecutive step developments on the main river for navigation, power development, and other purposes. The TVA system of water resource developments has gained worldwide recognition as a model of comprehensive river basin planning and development. A similar development is being made in the adjacent Cumberland River Basin by the Corps of Engineers.

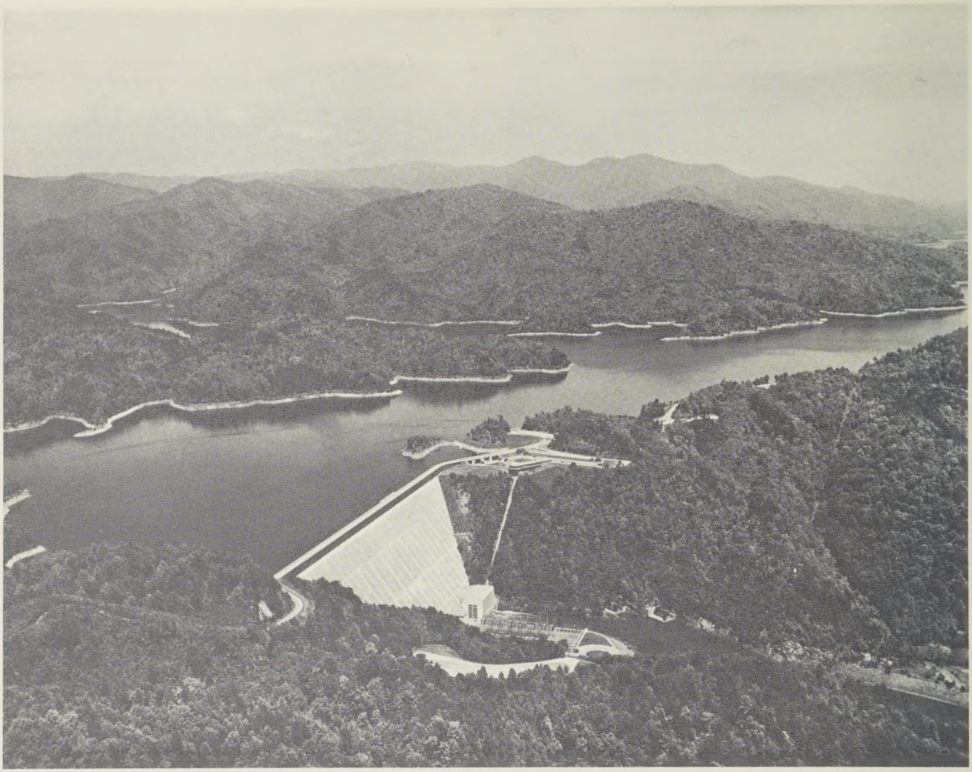
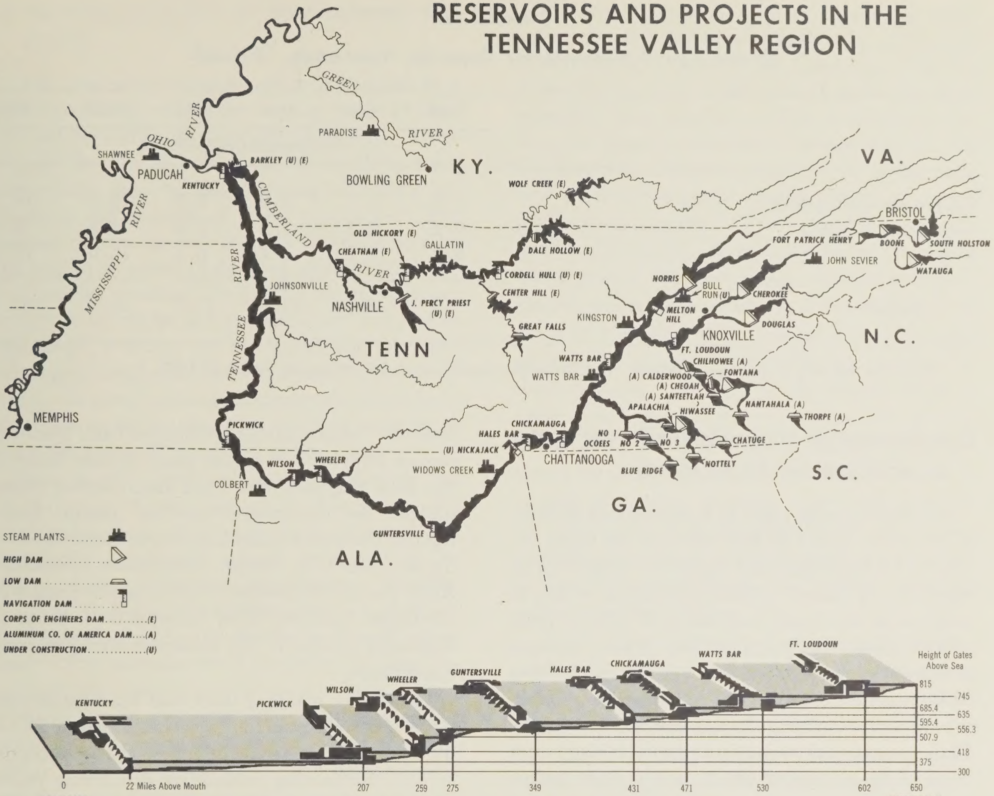


FIGURE 59 *The Fontana Dam in the TVA system of river development is the highest dam east of the Mississippi. Fontana headwater storage falls through 1330 feet of developed head—430 feet through the 202,000 kilowatt power plant at the dam and 900 feet in 11 downstream projects.*

TABLE 35

Federal Hydroelectric Capacity Jan. 1, 1964

Agency	Installed	Under construction	Authorized	Total
	(Millions of kilowatts)			
Corps of Engineers	8.4	4.4	8.1	20.9
Bureau of Reclamation	5.5	1.6	0.7	7.8
Tennessee Valley Authority	2.9	0.1	0.1	3.1
Total	16.8	6.1	8.9	31.8



RESERVOIRS AND PROJECTS IN THE TENNESSEE VALLEY REGION

PROFILE OF THE TENNESSEE RIVER

GREEN
RIVER
PARADISE
OHIO
RIVER
SHAWNEE
PADUCAH
KENTUCKY
BARKLEY (U) (E)
BOWLING GREEN
KY.
WOLF CREEK (E)
VA.
BRISTOL
FORT PATRICK HENRY
BOONE
SOUTH HOLSTON
JOHN SEVIER
WATAUGA
CUMBERLAND
RIVER
MISSISSIPPI
RIVER
OLD HICKORY (E)
GALLATIN
CHEATHAM (E)
DALE HOLLOW (E)
CORDELL HULL (U) (E)
CENTER HILL (E)
JOHNSONVILLE
NASHVILLE
J. PERCY PRIEST (U) (E)
NORRIS
BULL RUN (U)
CHEROKEE
MELTON HILL
KINGSTON
DOUGLAS
KNOXVILLE
N.C.
GREAT FALLS
TENN
TENNESSEE
FT. LOUDOUN
CHILHOWEE (A)
FONTANA
WATTS BAR
WATTS BAR
(A) CALDERWOOD
(A) CHEOAH
(A) SANTEETLAH
APALACHIA
HIWASSEE
NANTAHALA (A)
THORPE (A)
MEMPHIS
PICKWICK
CHICKAMAUGA
HALES BAR
NO 1
OCOEES
NO 2
NO 3
CHATUGE
(U) NICKAJACK
WILSON
WHEELER
WIDOWS CREEK
CHATTANOOGA
NOTTELY
BLUE RIDGE
S.C.
COLBERT
GA.
GUNTERSVILLE
ALA.
STEAM PLANTS
HIGH DAM
LOW DAM
NAVIGATION DAM
CORPS OF ENGINEERS DAM.........(E)
ALUMINUM CO. OF AMERICA DAM....(A)
UNDER CONSTRUCTION.............(U)
KENTUCKY
PICKWICK
WILSON
WHEELER
GUNTERSVILLE
HALES BAR
CHICKAMAUGA
WATTS BAR
FT. LOUDOUN
Height of Gates Above Sea
815
745
685.4
635
595.4
556.3
507.9
418
375
300
0
22 Miles Above Mouth
207
259
275
349
431
471
530
602
650
PADUCAH
KNOXVILLE

Figure 60

This same step development, frequently referred to abroad as the cascade concept of river improvement, is nearing completion on the main stem of the Columbia River where 11 major projects utilize nearly the full 1,288 feet of hydraulic head from the Canadian border down to sea level. A similar development is in progress on the main stem of the Snake River from Weiser, Idaho, down to the confluence of the Snake with the Columbia River near Pasco, Wash. Projects on the main stem of these two rivers will have an ultimate installed capacity in excess of 25 million kilowatts, about 35 percent of which is now operating. Development of the Columbia River basin is being carried out under multiple ownerships, including Federal, non-Federal public, and investor-owned. In most tributaries of the Columbia, the streamflow characteristics permit utilizing the same storage space in a reservoir for flood control, power and other conservation purposes.

Trends in Ownership of Hydroelectric Capacity

Through the years there have been major changes in the distribution of ownership of hydroelectric capacity. Before 1935 hydroelectric projects were constructed almost exclusively by electric power systems and industrial establishments. Since that time Federal installations have increased markedly, primarily as a result of developing power at multiple-purpose storage reservoirs and navigation dams. Installations by non-Federal public agencies have also increased rapidly in recent years. Hydroelectric capacity contributing to the public supply is shown by ownership classifications in table 36.

TABLE 36

Ownership of Hydroelectric Capacity, Year-ends, 1920–63

	1920	1930	1940	1950	1960	1963
	(Millions of Kilowatts)					
Investor-owned utilities	3.5	7.7	8.5	9.7	13.4	14.2
Non-Federal public	0.2	0.7	1.0	1.5	4.4	8.4
Federal	0.0	0.2	1.7	6.5	14.6	16.8
Total*	3.7	8.6	11.2	17.7	32.4	39.4

*Excludes capacity owned by industrial establishments amounting to 0.7 million kilowatts in 1963.

Development of Hydroelectric Power Under Comprehensive Basin Plans

All recent studies point to a tremendous increase in the years ahead in the demands on water resources for municipal and industrial water supply, water quality control, and water based recreation, in addition to the traditional needs of power, flood control, navigation, and irrigation. These demands of a growing population make it imperative that water resource developments be undertaken within the framework of long range comprehensive plans. Thus, an essential consideration in planning water resource developments which may include hydroelectric power is the harmonizing of the requirements of all water uses.

On some streams the preservation of anadromous fish is of particular significance. Intensive research that would solve the fish problems created by construction of dams would facilitate the early development of a number of remaining water power sites. In water shortage areas, such as southern California, Arizona, and Texas, water needs for consumptive uses are of paramount importance. Numerous large scale inter-basin water diversion plans are being considered to supply such needs. Some of these plans would include the development of hydroelectric power, and all would require large amounts of power for pumping purposes.

State and local interests, as well as Federal agencies, are becoming increasingly aware of the importance of planning for the comprehensive development and utilization of the Nation's water and related land resources. Most recent studies, and those now scheduled, provide for the cooperation of all interests. Important comprehensive basin planning studies completed in recent years include those of the New England-New York Inter-Agency Committee; the Arkansas-White-Red Basins Inter-Agency Committee; the U.S. Study Commission—Texas; the U.S. Study Commission—Southeast River Basins; the Bureau of Reclamation's study of the Upper Colorado River Basin; and the Corps of Engineers' studies of the Columbia and Delaware River Basins.

Despite the planning work that has been accomplished, there is need for a very large amount of additional work within the next few years. Recently, survey coordinating committees comprising representatives of affected States and Federal agencies have been established for a number of river basins, principally under the leadership of the Corps of Engineers, Department of the Army. The Federal Power Commission has staff representation on 19 of these committees. The objective of the committees is to guide the preparation of long-range basin plans for developing the water and related land resources.

The Federal Power Commission has intensified its river basin planning studies through the initiation of a program of water resource appraisals related primarily to its responsibilities for hydroelectric licensing. These studies are needed to enable the Commisison to carry out its broad responsibilities under the Federal Power Act for assuring comprehensive river basin development. The water resource appraisals program is designed to supplement the work of others in order to meet early Commission needs for analyses in particular basins.

Evaluation and Use of Hydroelectric Capacity

The amount of capacity which is installed in a hydroelectric plant and the manner in which it is utilized depend upon a number of factors. These include the available head and streamflow, reservoir storage capacity, and operating limitations imposed in the interests of other water uses. The amount of capacity installed may also be limited by the load to be served in the area within economical transmission distance. Frequently, an initial power installation is made and provisions are included in the project's design for the installation of additional generating units when warranted by increased loads. In many instances adequate provisions have not been made for expansion of plant capacity to serve the peaks of expanded system loads.

Some projects, such as those on the Niagara and St. Lawrence Rivers, have been designed to operate as baseload plants and others, principally in the Pacific Northwest, provide nearly all of the power to meet total load requirements. Usually, however, hydroelectric developments are designed to operate largely during the hours of peak power loads. The annual cost of providing peaking capacity by installing additional units in hydroelectric plants is less, in most cases, than the cost of additional capacity from alternative sources. Also, the ability to start quickly and change power output rapidly makes hydroelectric plants particularly suitable for carrying peak loads and for assisting in the supply of spinning reserve. Under such operation they complement thermal-electric plants which can be operated to serve the around-the-clock portions of the loads. Hydroelectric plants having seasonal or annual storage may have their operations scheduled to serve loads during only the months of peak kilowatt demands on the system. Plants having only sufficient storage for daily operations are used daily during the hours of peak load. The anticipated future rate of growth of electric loads, and the expected installation of large thermal-electric units, in the 1,000-megawatt range and higher, to operate at high capacity factors for best efficiency and economy, accentuate the need for peaking capacity to operate only a few hours per day. The interconnection of all of these generating sources over broad areas by EHV transmission lines will facilitate their optimum use.

The growing need for peaking capacity is resulting in planning for lower plant factor operations. However, the effects of such operations, with the accompanying high discharges of water for short periods of time, must be carefully studied to be certain that they are consistent with the overall basin development. Recently, hydroelectric plants have been planned and constructed to operate at annual plant factors [9] as low as five percent to meet particular system needs. Even in the Pacific Northwest where most of the load is now supplied by hydroelectric power, new plants are being designed for eventual peak-load use in conjunction with large amounts of capacity expected to be provided by thermal plants. Planning for the peaking needs to 1980 should include the reappraisal of available hydroelectric power sites and an analysis of the potential for adding capacity by the economic redevelopment of existing projects. Operated primarily for peaking power at low plant factor, project sites previously considered infeasible of development may be found to be economical as the need for additional peaking capacity develops.

The investment in hydroelectric projects per kilowatt of installed capacity varies greatly according to the type of project, its size and location, the cost of lands required, and the cost of relocations of highways, railroads, buildings and other improvements. When power is installed at multiple-purpose projects constructed by the Federal Government, the costs to be recovered by power revenues are determined by means of a cost allocation. Power bears the cost of all facilities provided specifically for power development plus an allocated share of the cost of facilities, such as the dam and reservoir, which are used jointly for power and other purposes such as flood control, navigation and irrigation.

On the average, the investment cost per kilowatt is substantially higher for hydroelectric plants than for thermal-electric plants. On the other hand, hydroelectric plant operating expenses are much lower, principally because no fuel is required and other operating and maintenance costs are less. The best of our hydroelectric developments provide the lowest cost power in the Nation.

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[9] Annual plant factor is the ratio of the average load on the plant during the year to the aggregate rating of all the generating equipment installed in the plant.

Trends in Hydroelectric Project Design

Hydroelectric generating units have been very efficient for many years, with hydraulic turbines normally operating at efficiencies of 90 percent or better. Thus, the opportunity for improving the economics of hydroelectric developments through higher efficiencies is limited.

Generally, investment and operating costs per kilowatt for power plant, waterways, and equipment can be decreased through the installation of large units. The rating of a unit is often limited, however, because the installation must be planned for particular site and head conditions. Adjustable blade propeller units called "Kaplan" type units with ratings of 135 megawatts are being installed in several plants in the Pacific Northwest. In this instance savings are being realized through repetitive design of powerhouses and equipment. Kaplan units with ratings of 150 megawatts or more may be practicable. At the Amistad plant on the Rio Grande, Kaplan units are being used under a design head of 150 feet, although the upper limit is considered to be about 100 feet for such units.

For Francis type turbines, fixed blade units which are normally cast in one piece, shipping restrictions may limit the unit size at many locations. In some cases this restriction in size is overcome by casting the turbines in sections and assembling them at the project site. The largest Francis unit now operating in the United States has a rating of 175 megawatts, but consideration is being given to the installation of units as large as 300 megawatts.

An increasing number of hydroelectric projects are being equipped for remote control to reduce operating costs. Plans are being made in the Pacific Northwest to operate five projects in the Lower Snake River Basin by remote control from the McNary project on the Columbia River. The ultimate capacity of these six plants is nearly 5 million kilowatts. Important projects in the Colorado and Missouri Basins are also being planned for remote control operation.

Economies are being realized through improvements in design and construction of dams. In many instances, rock-filled dams have proved to be economical and arch dams are planned for construction at sites on the Colorado River and the Middle Snake River where sites are suitable. The largest number of dams, however, are still constructed as concrete gravity or earth-filled structures.

Major advances have been made in techniques and equipment used in tunneling and underground excavation. Under suitable situations, underground powerhouses are proving to be economical and satisfactory. The Haas development in California has an underground power plant, and similar installations are being made at the Oroville project in California and at the Boundary project in the State of Washington.

The layouts of hydroelectric plants may be varied greatly to take advantage of site conditions. A design used at certain sites on the Columbia River to overcome space limitations is illustrated by the Rocky Reach arrangement in which the power plant is located in the center of the river with the discharge from the units being almost at right angles to the flow of the stream.

An example of an unusual design is the Wells dam, under construction on the Columbia River, where a space-saving design combining powerhouse and spillway in a single structure is being used. The turbines, intakes, spiral case, draft tubes and unwatering facilities are to be located in the base of the dam, utilizing space under the spillway crest. The generators and auxiliary electrical and mechanical equipment are to be housed in the piers which support the spillway gates, and the transformers and switchyard are to be located on the top deck of the structure.

Development of Low-Head Sites

Within the last decade, research and development work, particularly in Europe, has produced designs for turbines which offer possibilities for developing economically the power potential of sites with heads as low as 10 to 15 feet. There are, for example, some 800,000 kilowatts of potential capacity which could be developed, if found to be economically feasible, at navigation dams on the Ohio River where the heads range from 16 to 35 feet.

The passage of water through these low-head turbines is generally parallel to the common axis of the conduit and the turbine-generator. In one type, the tube unit, the generator is mounted outside of the water passage on the extended shaft of the turbine. The Department of the Interior has recommended the use of this type of unit in its

INCLINED TUBE TURBINE

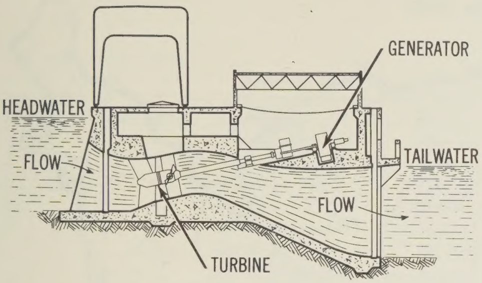


Figure 61

study of the Passamaquoddy tidal power project where the head would average about 13 feet. A transverse section of design for this unit is shown in figure 61. A small tube-type unit has recently been installed at a plant in Wisconsin. Another type of low-head turbine, the bulb-type, has the generator directly connected to the turbine and encased in a steel bulb centered within the penstock, or water passage. No bulb-type installation has been made in the United States, but a number of such installations have been constructed in European countries.

These turbines are comparable in efficiency to the conventional adjustable blade propeller turbine. However, in cases where a large volume of water is available for discharge through a relatively low head, the units have space-saving advantages that result in reductions of overall installation costs. The unit design permits a substantial decrease in the size of the powerhouse and reduces the depth required for trailrace excavation.

Projected Hydroelectric Developments

An appraisal has been made by the Federal Power Commission staff of the undeveloped water power sites to select those projects that might be developed for use during the period to 1980. In examining the economics of potential projects which have already received congressional authorization or have some licensing status, the annual charges used were those appropriate to the sponsoring entity. In screening other potential projects for which a sponsoring entity was not clearly identified, project economics were checked on the basis of Federal financing to assure inclusion in the list, all projects that could be justified on this basis, but with full recognition that in many cases development would be accomplished by non-Federal entities.

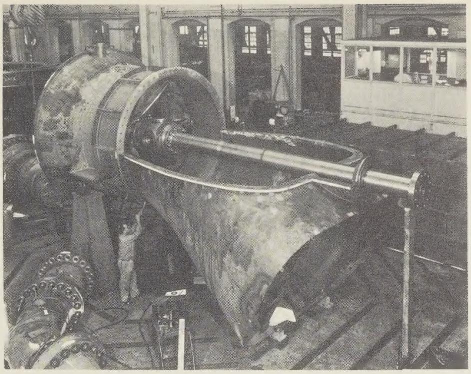
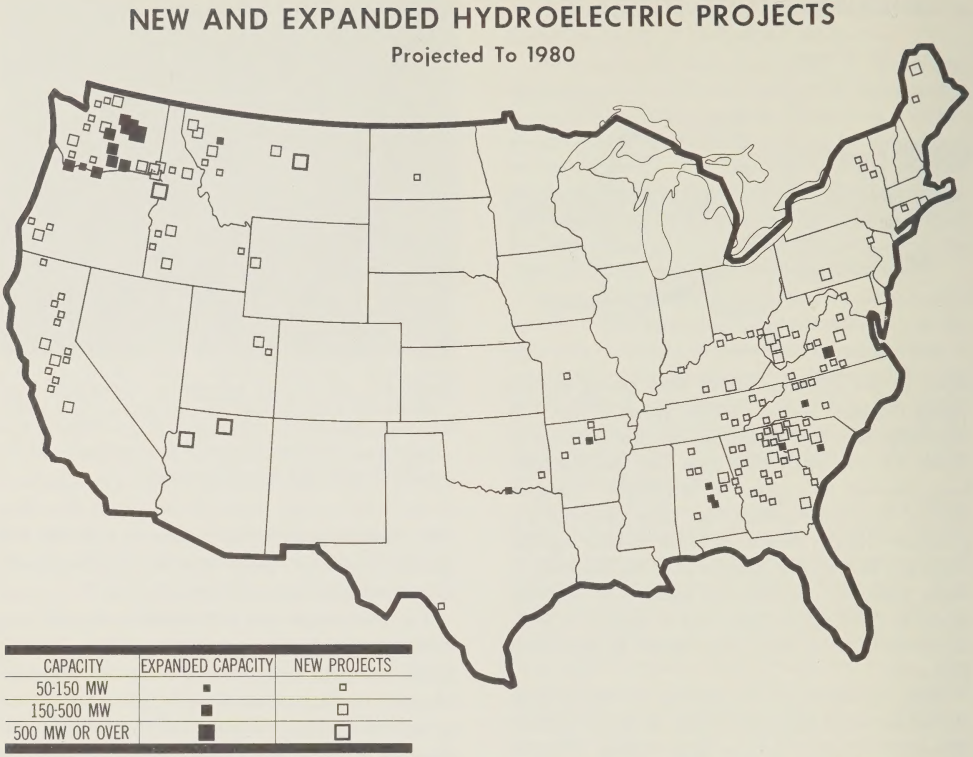


Figure 62 *The inclined tube turbine shown above, and the somewhat similar bulb type turbine, are fairly recent advancements for low head applications. Their design permits economies in the size of the powerhouse and the depth of excavation for water passages.*

The selection of new hydroelectric capacity was based upon information currently available. Additional economic and other studies would be needed for most of the projects before construction could be initiated. The projects selected would provide about 28 million kilowatts of new capacity, not including capacity in projects now under construction.

Among the major opportunities for new projects or capacity additions are the following: Dickey (or alternative) on the St. John River, Maine (475 mw); 13 projects in the Savannah River basin, Georgia and South Carolina (1,500 mw); 8 projects in the Alabama River basin, Alabama (800 mw); 13 projects in the Sacramento-San Joaquin River basin, California (1,500 mw); 3 projects in the Colorado River basin (2,400 mw); 2 projects in the Missouri River basin (1,000 mw); 14 new projects and capacity additions in the Snake River basin (4,500 mw); and capacity additions at projects on the Columbia River (3,400 mw).

Figure 63 shows the locations of projected new projects and capacity additions having ratings of 50 megawatts or more. These projects and capacity additions are listed by coordination study areas in table 37.


NEW AND EXPANDED HYDROELECTRIC PROJECTS
Projected To 1980
CAPACITY
EXPANDED CAPACITY
NEW PROJECTS
50-150 MW
■
□
150-500 MW
■
□
500 MW OR OVER
■
□

NOTE: Capacity Existing or Under Construction as of January 1, 1964 is not Shown

Figure 63

TABLE 37

New Hydroelectric Projects and Capacity Additions Projected to 1980

(Listed projects or additions would have installations of 50 mw or more)

Coordination study area	Name of project	River	State	Installed capacity, mw Capacity additions	New projects
A—New England	Dickey	St. John	Maine	....	475
	Cold Stream	Kennebec	Maine	....	90
	Enfield	Connecticut	Connecticut	....	90
B—New York	Kettle Mountain	Hudson	New York	....	78
	Hadley	Hudson	New York	....	82
	Hudson Falls	Hudson	New York	....	90
C—Pennsylvania-New Jersey-Maryland	Tocks Island	Delaware	New Jersey	....	50
	Raystown	Juniata	Pennsylvania	....	270
D—Ohio Valley	Gallipolis	Ohio	Ohio-West Virginia	....	50
	Greenup	Ohio	Ohio-Kentucky	....	70
	Capt. A. Meldahl	Ohio	Ohio-Kentucky	....	70
	Cannelton	Ohio	Indiana-Kentucky	....	70
	Moores Ferry	New	Virginia	....	50

TABLE 37—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw Capacity additions	Installed capacity, mw New projects
D—Ohio Valley—Con.	Bluestone	New	West Virginia		180
	Sandstone	New	West Virginia		240
	Thurmond	New	West Virginia		200
	Summersville	Gauley	West Virginia		R90
	Carnifex	Gauley	West Virginia		220
	Falmouth	Licking	Kentucky		100
	Devils Jumps	Big South Fork	Kentucky		480
	Smith Mountain	Roanoke	Virginia	R150	
	Schoolfield	Dan	Virginia		76
	Seneca	Potomac	Maryland-Virginia		62
E—Carolinas-Virginia	Salem Church	Rappahannock	Virginia		102
	Gathright	Jackson	Virginia		81
	Maury	North	Virginia		69
	Pemberton	James	Virginia		232
	Randolph	Roanoke	Virginia		50
	Melrose	Roanoke	Virginia		50
	Junction	Yadkin	North Carolina		69
	Styers	Yadkin	North Carolina		54
	Upper Donnaha	Yadkin	North Carolina		90
	Crumps Ford	Rocky	North Carolina		79
	Courtney Island	Catawba	South Carolina		87
	Cowans Ford	Catawba	North Carolina	87	
	Saluda	Saluda	South Carolina	65	
	Frost Shoals	Broad	South Carolina		150
	Blairs	Broad	South Carolina		184
	Greater Lockhart	Broad	South Carolina		179
	Greater Gaston Shoals	Broad	South Carolina		128
	Clinchfield	Broad	North Carolina		59
	Stokes Bluff	Savannah	South Carolina		D30
	Burtons Landing	Savannah	South Carolina		D50
	Trotters Shoals	Savannah	South Carolina-Georgia.		310
	Horsepasture	Horsepasture	North Carolina		58
	Newry-Old Pickens	Keowee	South Carolina		150
	War Woman	Chattooga	South Carolina-Georgia.		80
	Sand Bottom	Chattooga	South Carolina-Georgia.		66
	Rogues Ford	Chattooga	South Carolina-Georgia.		120
	Camp Creek	Chattooga	South Carolina-Georgia.		100
	Jocassee	Keowee	South Carolina		150
F—Tennessee Valley	Tellico	Little Tennessee	Tennessee		135
	Austral	Hiwassee	Tennessee		70
	Nemo	Obed	Tennessee		80
	Surgoinsville	Holston	Tennessee		72
	Sugar Creek	Elk	Alabama		100
	Erwin	Nolichucky	Tennessee		65
	Celina	Cumberland	Kentucky		69
G—Southeastern	Stokes Bluff	Savannah	Georgia		D30
	Burtons Landing	Savannah	Georgia		D50
	Hartwell	Savannah	Georgia-South Carolina.	66	

See footnotes at end of table.

TABLE 37—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw	
				Capacity additions	New projects
G—Southeastern—Con.	Anthony Shoals	Broad	Georgia		100
	Tallow Hill	Broad	Georgia		172
	Goose Creek	Altamaha	Georgia		180
	Laurens Shoals	Oconee	Georgia		95
	Coopers Ferry	Ocmulgee	Georgia		50
	Abbeville	Ocmulgee	Georgia		50
	New Riverview	Chattahoochee	Alabama-Georgia		65
	West Point	Chattahoochee	Georgia		107
	Franklin	Chattahoochee	Georgia		50
	Cedar Creek	Chattahoochee	Georgia		50
	L. Auchumpkee Creek	Flint	Georgia		81
	Lazer Creek	Flint	Georgia		87
	Spewrell Bluff	Flint	Georgia		100
	Jones Bluff	Alabama	Alabama		68
	Jordan No. 2	Coosa	Alabama	75	
	Mitchell	Coosa	Alabama	65	
	Lay	Coosa	Alabama	96	
	Emuckfaw	Tallapoosa	Alabama		160
	Crooked Creek	Tallapoosa	Alabama		113
	Kingston	Etowah	Georgia		69
	Gilmer	Etowah	Georgia		69
	Smiths Ford	Locust Fork	Alabama		115
	Dorsey Creek	Mulberry Fork	Alabama		63
H—Lower Michigan	None				
J—Texas	Denison	Red	Texas-Oklahoma	105	
	Amistad	Rio Grande	Texas		57
K— Middle South	Kaysinger Bluff	Osage	Missouri		88
	Wolf Bayou	White	Arkansas		210
	Lone Rock	Buffalo	Arkansas		90
	Norfork	North Fork	Arkansas	70	
	Gilbert	Buffalo	Arkansas		60
	Ozark	Arkansas	Arkansas		70
	Pine Creek	Little	Oklahoma		86
L—Upper Mo. Basin	Bismarck	Missouri	North Dakota		100
M—New Mexico and Panhandle.	None				
N—Southwest	Auburn-Folsom	North Fork American	California		240
	Colgate (new)	North Fork Yuba	California		122
	Bullards Bar (new)	North Fork Yuba	California		130
	Hartman	Middle Fork Feather	California		54
	Bald Rock	Middle Fork Feather	California		75
	New Melones	Stanislaus	California		150
	Colliersville	Stanislaus	California		115
	Big Trees	North Fork Stanislaus	California		50
	New Don Pedro	Tuolumne	California		130
	Exchequer (new)	Merced	California		125
	Bagby	Merced	California		70
	Pine Flat	Kings	California		150
	Bridge Canyon	Colorado	Arizona		1, 500
	Marble Canyon	Colorado	Arizona		510
O—Colorado-Wyoming.	Snake Narrows	Snake	Wyoming		270
P—Northwest	Bonneville	Columbia	Washington-Oregon	324	
	The Dalles	Columbia	Washington-Oregon	142	

TABLE 37—Continued

Coordination study area	Name of project	River	State	Installed capacity, mw	
				Capacity additions	New projects
P—Northwest—Con.	John Day	Columbia	Washington-Oregon	270	
	Mossyrock	Cowlitz	Washington		300
	Muddy	Lewis	Washington		110
	B-Z	White Salmon	Washington		50
	Priest Rapids	Columbia	Washington	158	
	Wanapum	Columbia	Washington	166	
	Wenatchee	Wenatchee	Washington		180
	Rocky Reach	Columbia	Washington	304	
	Wells	Columbia	Washington	212	
	Chief Joseph	Columbia	Washington	513	
	Grand Coulee	Columbia	Washington	1, 310	
	Knowles (or Alt.)	Flathead	Montana		256
	Kerr	Flathead	Montana	56	
	Quartz Creek	Clark Fork	Montana		78
	Ninemile Prairie	Blackfoot	Montana		60
	Kootenai Falls	Kootenai	Montana		180
	Libby	Kootenai	Montana		420
	Garden Valley	Payette	Idaho		369
	Lucky Peak	Boise	Idaho		60
	Guffey	Snake	Idaho		85
	Thousand Springs	Snake	Idaho		150
	Burns Creek	Snake	Idaho		90
	Ice Harbor	Snake	Washington	180	
	Lower Granite	Snake	Washington		405
	Lenore	Clearwater	Idaho		85
	Penny Cliffs	Middle Fork Clearwater.	Idaho		292
	Asotin	Snake	Idaho-Washington		384
	Wenaha	Grande Rhonde	Washington		201
	China Gardens	Snake	Idaho-Washington		180
	High Mt. Sheep	Snake	Oregon-Idaho		1, 750
	Lower Sauk	Skagit	Washington		94
	Copper Creek	Skagit	Washington		83
	Thunder Creek	Skagit	Washington		152
	Trout Creek	Snohomish	Washington		90
	Sultan No. 1	Sultan	Washington		84
	Buzzard's Roost	Illinois	Oregon		250
	Lost Creek	Rogue	Oregon		52
	Eden Ridge	South Fork Coquille	Oregon		77
	Salt Caves	Klamath	California		77
	Gray Canyon	Green	Utah		400
	Sixth Water	Diamond Fork	Utah		90
	Fort Benton	Missouri	Montana		300
	High Cow Creek	Missouri	Montana		720
	Subtotal			4, 414	21, 081
	Installations of 50 mw or more				25, 495
	Installations of less than 50 mw				2, 717
	Grand total				28, 212

D—Capacity divided between two coordination study areas.
R—Denotes plant with reversible capacity in addition to that shown.

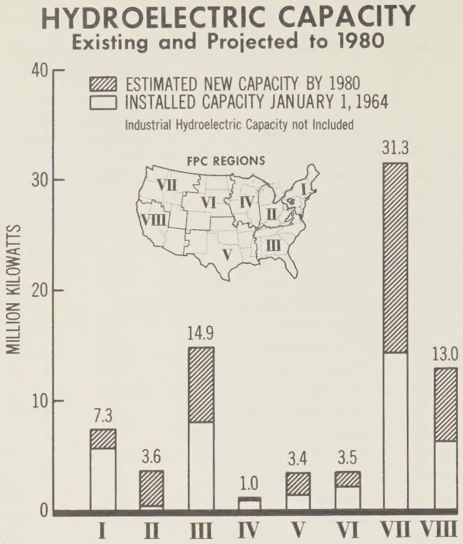


Figure 64

Completion of the projected new capacity, together with the capacity under construction, would increase the developed utility hydroelectric capacity to about 78 million kilowatts. This is about twice the developed capacity on January 1, 1964, but only about 15 percent of the country's total generating capacity needs for 1980. The amounts of existing and projected hydroelectric capacities for 1980 are indicated by FPC regions on figure 64. Table 38 summarizes the amounts of hydroelectric capacity available for public supply, existing and projected for 1970 and 1980.

TABLE 38

Existing and Projected Hydroelectric Capacity to 1970 and 1980

	Millions of kilowatts
Existing capacity	39
Capacity under construction	11
Other capacity proposed for construction to 1970	5
Subtotal 1970	55
Additions to 1980	23
Total 1980	78

In making the foregoing selections, only those capacities usable in the regions in which the projects are located, as determined from projected load curves, were considered for installation by 1980. The availability of electrical interconnections among regions might well permit the economic development and use of additional hydroelectric power in certain river basins, particularly in the Pacific Northwest.

Hydroelectric plants are the principal source of electric power supply in the Pacific Northwest. During the season of high streamflows, extending from April to September, substantial amounts of hydroelectric energy can be generated for which there is no local market at present. Congress has recently approved the Federal portion of a plan for an EHV interconnection between the Pacific Northwest and the Pacific Southwest to utilize such power. It is estimated that with transmission facilities having a capacity of 2,000 megawatts, some 10 billion kilowatt-hours of such surplus energy now wasted could, on the average, be exported annually in 1970. The estimated exportable surplus energy is expected to decrease to about 5 billion kilowatt-hours annually by 1980 and about 2 billion by 1985.

Several projects in operation or under construction in the Columbia River basin could include additional capacity that would not be immediately usable in the Pacific Northwest, but could be made available for early use in other regions. A total of about 4 million kilowatts of exportable peaking capacity could be provided at John Day (1,080 mw), The Dalles (624 mw), Chief Joseph (704 mw), and McNary (420 mw) on the Columbia River; and Lower Monumental (405 mw), Little Goose (405 mw), and Lower Granite (405 mw) on the Snake River. The added exportable secondary energy associated with these capacity additions would amount to approximately 4.3 billion kilowatt-hours annually.

The availability of regional interties would also permit advantage to be taken of diversities in streamflow and, as a result, improvement in the firm power output from hydroelectric resources in the interconnected areas. Significant gains would be limited generally to regions in which hydroelectric power provides a large part of the total supply.

It is estimated that differences in the periods of critical streamflows among the Columbia, Colorado, and Missouri River basins would make possible an estimated gain of continuous power of about 900 megawatts by 1980. (See table 39.)

TABLE 39

Estimated Gains in Average Critical Period Hydroelectric Output from Diversity of Streamflows in the Columbia, Colorado, and Missouri River Basins

	Average power output [1]			
	Non-coincidental	Coincidental	Gain	
	(Avg. mw)	(Avg. mw)	(Avg. mw)	(Percent)
Columbia-Colorado-Missouri	19, 570	20, 490	920	4. 7
Columbia-Colorado	18, 370	18, 890	520	2. 8
Columbia-Missouri	17, 000	17, 400	400	2. 4
Colorado-Missouri	3, 770	3, 770	0	0

[1] Critical Periods: Columbia, August 1928–February 1932; Colorado, July 1930–September 1941; Missouri, July 1930–September 1941.

Diversities in the seasonal occurrence of secondary hydroelectric energy could also be utilized advantageously in the operation of storage reservoirs. The transfer of surplus secondary energy from the Pacific Northwest to Arizona and adjacent areas would be useful in replacing generation from hydroelectric projects on the Colorado River. This would permit additional refill of large Colorado River storage projects such as Glen Canyon and Hoover. There would be less advantage in transmitting surplus Pacific Northwest energy to the Missouri River basin area, because surplus periods of spring and summer months in the Pacific Northwest coincide generally with the navigation season on the Missouri River. During that season the Missouri River reservoirs are drawn down to provide required navigation flows, with incidental high rates of power generation.

Hydroelectric Power From Alaska

The studies of power supply to 1980 for the 48 contiguous States do not reflect the possibility of importing hydroelectric power from Alaska. Studies should be made, however, of the possibilities of utilizing Alaska's large hydroelectric power potential for local use and for future export to the Pacific Northwest under arrangements mutually beneficial to Canada and the United States. Some Alaskan sites could be developed to produce large amounts of power at costs estimated to range from 2.0 to 2.5 mills per kilowatt-hour at points of generation, based on Federal financing.

Among the more favorable Alaskan sites are Rampart Canyon (4,800 mw) and Woodchopper Creek (2,400 mw) on the Yukon River, Crooked Creek (600 mw) on the Kuskokwim River, and Wood Canyon (1,100 mw) on the Copper River. Another large power possibility, requiring agreement with Canada, is the Yukon-Taiya project (1,600 mw) involving a diversion to tidewater near Skagway. The locations of these project sites are shown in figure 65. The five projects would provide more than 10 million kilowatts of hydroelectric capacity. Rampart Canyon is the largest of these and apparently would provide the lowest cost power. Its installation would be nearly 5 million kilowatts, and its vast reservoir of 1,250 million acre-feet would be about 40 times the capacity of Lake Mead at Hoover Dam. It would require nearly 20 years to fill the reservoir under a program of retaining about 75 percent of the average annual runoff. An output of about 350 megawatts would be possible approximately 7 years after the initiation of construction, and this could be doubled in another 5 to 7 years.

Potential Hydroelectric Imports From Canada

The large water power resources of Canada have been, and are being, developed and utilized as needed to supply the bulk of the growing power needs of that country. Many of the large undeveloped sites may be expected to be utilized within the near future to supply anticipated Canadian powerloads. There are, however, several large

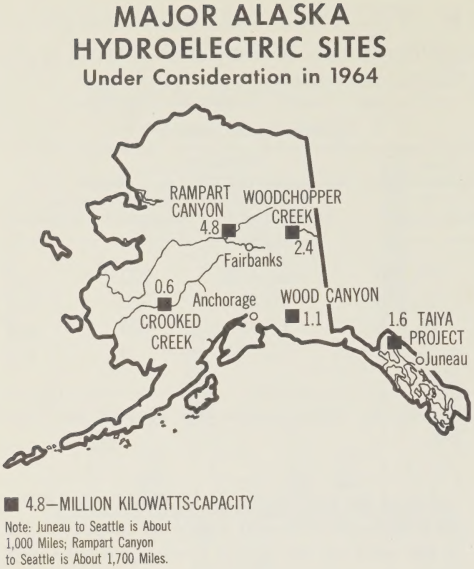

MAJOR ALASKA HYDROELECTRIC SITES
Under Consideration in 1964
RAMPART CANYON
4.8
WOODCHOPPER CREEK
2.4
Fairbanks
0.6
CROOKED CREEK
Anchorage
WOOD CANYON
1.1
1.6 TAIYA PROJECT
Juneau
■ 4.8—MILLION KILOWATTS-CAPACITY
Note: Juneau to Seattle is About 1,000 Miles; Rampart Canyon to Seattle is About 1,700 Miles.

FIGURE 65

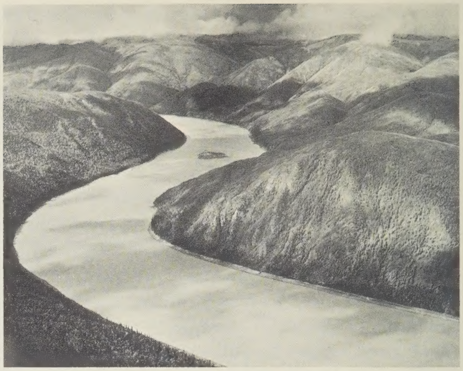


FIGURE 66 *The construction of a dam in the Rampart Canyon of the Yukon River in Alaska would create a huge reservoir holding 1,250 million acre-feet of water, or 40 times the capacity of the reservoir behind Hoover Dam. This project is a potential source of 4.8 million kilowatts of economical hydroelectric capacity.*

known sites which have capabilities in excess of expected needs in Canada for extended periods of time. These sites provide opportunities for the development of substantial blocks of power for export to the United States under long-term contracts.

The export of power from Canada requires a license from the National Energy Board of the Canadian government. The National Energy Board Act of 1959 provides that the duration of export licenses shall not exceed 25 years. The Canadian government currently is encouraging coordination among the electric systems in the United States and Canada and, in particular, the long-term export of surplus power in order to expedite the development of major projects which are too large to be supported by the present Canadian market.

Among the water power sites in Canada that might be developed for such long-term power export to the United States are those on the Hamilton River in Newfoundland, on the Nelson River in Manitoba, and on the Columbia and Peace Rivers in British Columbia. (See fig. 67).

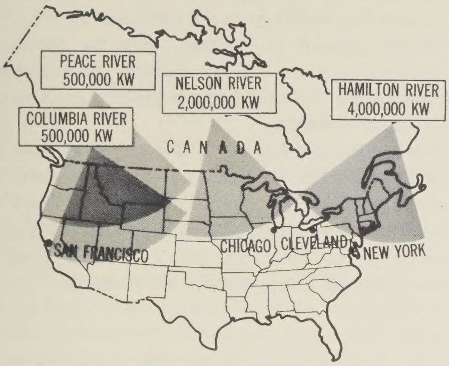
Based on available information, it appears that the amounts of power shown in table 40 could be considered available for import into the United States, under contracts of up to 25 years, with costs, including transmission of the power, probably competitive with power available from alternative sources in the United States:

TABLE 40

Canadian Hydroelectric Power Potentially Available for Export

River Basin	Canadian Province	Capacity, million kw	Annual energy, billion kwh	Capacity factor, percent
Hamilton	Newfoundland	4.0	28	80
Nelson	Manitoba	2.0	14	80
Columbia and Peace	British Columbia	1.0	7	80

CANADIAN HYDROELECTRIC POWER POTENTIALLY AVAILABLE FOR EXPORT TO U.S.



Projected Area Radius Equals 1,000 Miles

Figure 67

There has been considerable discussion of the early development of a large hydroelectric plant on the Hamilton River and the import of about 2,000 megawatts of high load factor power to the New York and New England area. The amount shown in the table for the Columbia River does not include the Canadian entitlement under the Columbia River Treaty, which, as discussed in the next paragraph, will be marketed for an interim period in the United States under recently completed plans.

Columbia River Treaty

A draft of a treaty between Canada and the United States concerning developments in the Columbia River Basin was completed and approved by negotiators of both countries on January 17, 1961. It was ratified by the U.S. Senate in March 1961 and by the Canadian Parliament in June 1964.

The terms of the treaty provide for construction by Canada of 15.5 million acre-feet of storage at Duncan, High Arrow, and Mica sites in Canada, with 8.5 million acre-feet at Duncan and High Arrow to be completed within 5 years and the remainder within 9 years after ratification. The United States would pay Canada $64.4 million for flood control benefits, Canada would give consent to construction by the United States of the Libby Project, and the United States and Canada would share equally in the dependable capacity and average annual energy provided at downstream United States plants by the proposed Canadian storage. Procedure for determining these power benefits is outlined as part of the Treaty.

In January 1964, representatives of the two Governments agreed to use their best efforts to arrange for an agreement whereby the Canadian share of power gains in the United States would be sold in the United States for a period terminating 30 years after all the storage is completed. The purchase price is $254 million, to be paid upon consummation of the Treaty. The Canadian entitlement is estimated to be about 1,450 megawatts of dependable capacity in the early years and about 7 billion kilowatt-hours of annual energy. By the end of the purchase period the entitlement would decline to an estimated 175 megawatts of dependable capacity and about 860 million kilowatt-hours of annual energy. The Treaty and power-purchase arrangement became effective in September 1964.

Summary and Conclusions

Conventional hydroelectric projects have many favorable characteristics which provide strong incentives for developing our remaining potential water power sites. They utilize a renewable resource, they do not contribute to thermal and air pollution, and they are very reliable in operation. Because of their ability to start quickly and make rapid changes in power output, they are particularly well adapted for serving peak loads and for assisting in the supply of spinning reserve. In many cases the development of hydroelectric power provides such associated benefits as recreation, water supply, fish and wildlife enhancement, and flood control. The increasing demands of these purposes provide impetus for the preparation of long-range basin plans harmonizing the water requirements for all uses.

Development of new hydroelectric capacity will continue at a good rate but not as fast as the rate of load increase. Although the number of remaining economical sites diminishes as development takes place, the gradual movement of hydroelectric power into the peak of the load has bolstered project power benefits. This has permitted consideration of many possibilities which formerly were marginal or uneconomical under higher load factor standards.

For the 48 contiguous States the total estimated hydroelectric potential is 134 million kilowatts of capacity. This includes the capacity of undeveloped sites, not all of which are likely to be economically feasible of development. Of the total potential, approximately 40 million kilowatts of capacity have been developed, including 0.7 million kilowatts owned by industrial establishments.

Under patterns that have evolved over a period of several decades, major hydroelectric developments are constructed and operated by Federal agencies under congressional authorization, or by non-Federal interests under licenses issued by the Federal Power Commission. Licenses cover some 17.7 million kilowatts of existing capacity, and about 4.7 million kilowatts of capacity under construction.

Federal hydroelectric projects in operation have a total installed capacity of 16.8 million kilowatts, and an additional 6.1 million kilowatts of Federal hydroelectric capacity are under construction. During the past 30 years, the portion of total hydroelectric capacity in Federal plants has increased markedly as a result of the inclusion of hydroelectric power in multiple-purpose projects constructed by the Government.

It is estimated that by 1980 the hydroelectric capacity available for power system supply will increase to about 78 million kilowatts, or about 15 percent of total generating capacity needs. A major portion of the added capacity will be in plants in the Southeast and in the Pacific Northwest.

CHAPTER 7

PEAKING POWER

Peaking capacity is generally understood to mean that part of a system's generating equipment which is operated intermittently for short periods during the hours of highest daily, weekly, or seasonal kilowatt demand.

Variations in power demands are caused by many factors but usually the maximum loads result from weather extremes superimposed on the more normal peaks associated with the living habits and work schedules of the population served and characteristics of the industries included in the load. Peaks in the demand for electricity normally occur at certain hours of the day, days of the week, and seasons of the year.

For a typical system, electric power loads on a weekday increase from a minimum during the early morning hours to a high level in the forenoon and during the afternoon, and then reach a maximum peak in the late afternoon, after which they decrease slowly during early evening hours, and rapidly in the late evening. For some systems the larger peak occurs in the morning. During weekends and holidays loads are usually at much lower levels than on normal weekdays. Hourly variations in load on a large utility system are depicted on the typical weekly load curve shown in figure 68. As the diagram indicates, a large part of the system's capacity must operate around the clock but much of the capacity is used only part time.

Whether the maximum peak demand of a system lasts for a few minutes or a few hours, generating capacity must be available for supplying the demand at the moment it develops. Ideally, peaking capacity should be low in first cost, should be able to start quickly and operate satisfactorily at partial load, and should require little manpower, or be capable of remote operation.

It is of course desirable to utilize generating equipment as fully as possible. It is anticipated that average generating plant factors, which are a measure of the percent of use of system capacity, will improve as off-peak loads are developed and interconnection and coordination of systems increase. There is some diversity in load patterns between most systems, and interconnection of systems and coordinated planning for use of generating equipment permit serving combined loads with less total capacity. Some improvements in system load factors are also possible through the development of rate structures and sales practices which will encourage new uses of off-peak energy, and which will induce consumers to shift some existing loads from peak hours to off-peak periods. Thus, the ratio of peaking capacity to total capacity can be expected to diminish appreciably by 1980. Nevertheless, relatively high peaks in demand will be unavoidable, and supplying these demands will continue to be a significant factor in the overall cost of generation.

It is the practice, as new efficient thermal units are installed, to place them in baseload service, shifting the position of existing capacity to supply loads at somewhat lower load factors. Much of the capacity that serves loads in the intermediate load factor range is usually supplied by steam units which have been in operation for 15 to 20 years. Sometimes systems will retain units in service too long, a temptation that exists as they become fully depreciated, and thus have the appearance of offering low cost peaking service. This practice frequently proves to be short-sighted and uneconomic, particularly when such units are small in size, have high heat rates, and incur high operation and maintenance costs. Dependence on such units may tend to discourage vigorous promotion of new loads. Their retention may restrict the introduction of new capacity, either in highly efficient baseload units or low cost units specially designed for serving peak loads, and thus can severely retard the progressive and efficient growth of the system's capacity.

Utility systems are experiencing various trends in new capacity expansion. Most of the new steam-electric generation will be in large high-efficiency baseload units which are not designed for flexible peaking service. These units cannot be placed on

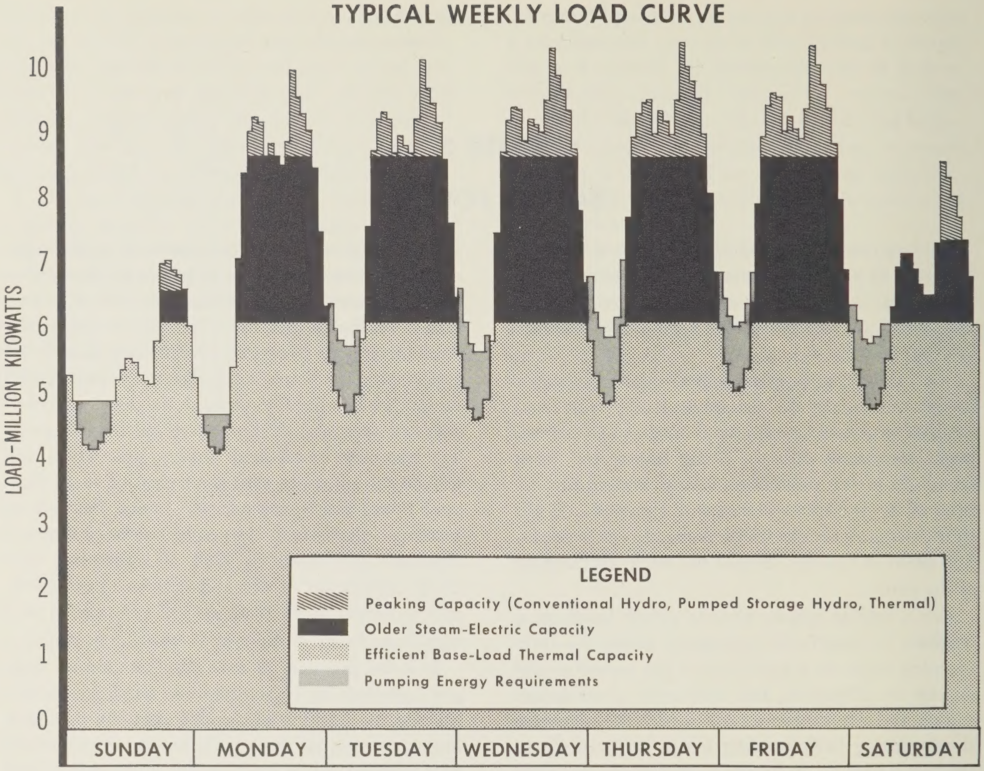


FIGURE 68

or taken off the line quickly. They require warming up and cooling down at carefully controlled rates in order to protect pressure parts and rotating elements from excessive thermal stresses and uneven expansion. Large, conventional, baseload units are most efficient when operated at or near design ratings. Their efficiency drops as the unit output decreases, and a substantial reduction in efficiency may occur when the output is reduced below about 50 percent of a unit's design rating. These units will, therefore, be utilized for baseload operation during a greater part of their lifetime.

In view of this probability, there will be an increasing need, as systems expand to meet the loads between now and 1980, for installing new capacity particularly suited to lower plant factor operation. The discussions of this chapter deal especially with these types of peaking capacity which include: hydro, pumped storage, steam turbines designed specifically for peaking, steam peaking capacity integral with base load units, gas turbines, and diesel engines. These peaking capacities are in addition to the peaking service derived from assigning older existing units to low plant factor operation.

The portion of the load normally supplied by peaking capacity installations is shown in the top portion of the load curve in figure 68. This figure illustrates also the normal assignment of steam-electric capacity of medium efficiency to serve intermediate loads.

Conventional Hydro Peaking Capacity

Conventional hydroelectric developments are becoming increasingly important as sources of peaking capacity. The merits of hydro capacity in this service have already been described in chapter 6.

Pumped Storage Peaking Capacity

A pumped storage plant generates electric energy during system peak load periods, using hydroelectric

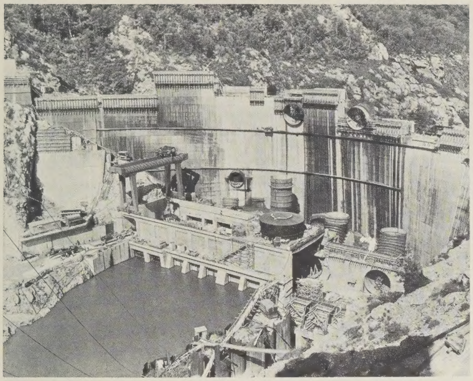


FIGURE 69 *The Smith Mountain Project of the Appalachian Power Company on the Roanoke River is an example of combined conventional hydroelectric generation and generation from pumped storage. Ultimately, the plant will have a capacity of 582,000 kilowatts, about double that possible without the provisions for pumped storage.*

units driven by water from a headwater pool. During off-peak periods energy from other sources, usually from steam-electric plants, is used to pump water from a lower pool back to the headwater pool. The water in the upper pool may thus be regarded as the equivalent of stored steam-generated energy. The pumped storage generating plants have many of the favorable characteristics of conventional hydroelectric plants for peaking and reserve use. Figure 70 illustrates the operating cycle of a pumped storage installation.

A prerequisite for a pumped storage development is the availability of energy at low incremental cost for the pumping cycle. For every 2 kilowatt-hours of energy generated, approximately 3 kilowatt-hours of energy are required for pumping. Reduced equipment cost brought about by the development in recent years of the reversible pump-turbine unit, permitting pumping and generating operations to be combined in a single machine, has contributed importantly to the economics of pumped storage installations.

Pumped storage projects are usually more economically developed at sites having high heads. The heads of existing projects range up to 820 feet, but additional projects are being planned with heads in excess of 1,000 feet. Costs of development depend upon individual site conditions. Economically attractive projects generally cost $100 to $120 per kilowatt or less.

Types of Pumped Storage Developments

Pumped storage installations can be divided into two general categories, those in which pumped storage facilities are added to a conventional hydro installation, and those which are exclusively pumped storage and generate power by recirculating the water between a lower and a higher reservoir. Within these two categories, pumped storage installations vary widely in design and modes of operation.

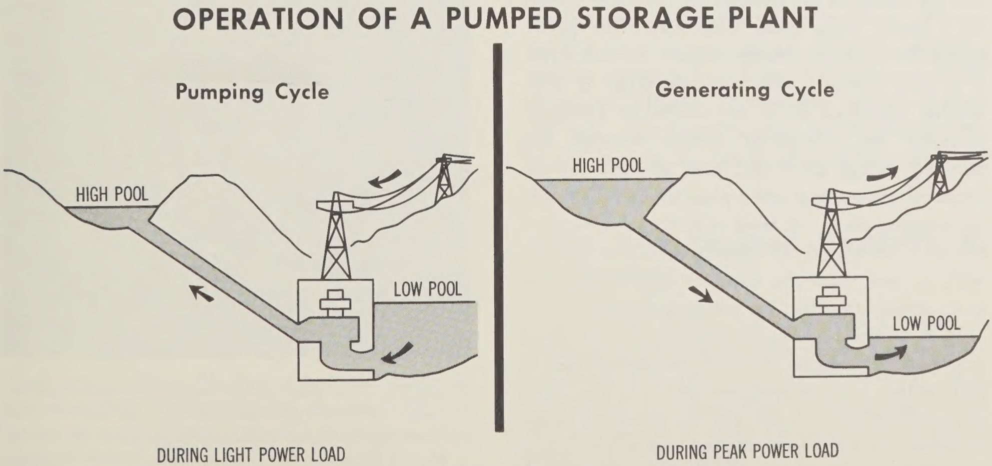


FIGURE 70

The inclusion of pumped storage facilities in a conventional hydro plant can bring about a major increase in the dependable capability of the installation. For example, the planned ultimate installation of 582 megawatts at the Smith Mountain project, now under construction on the Roanoke River, Virginia, is several times the capacity that would be warranted without the inclusion of pumped storage facilities. Combining pumped storage with conventional hydro makes possible the use of lower stream-flows and smaller reservoir capacities to provide substantial amounts of peaking capacity. Thus, combined pumped storage may significantly increase the number of sites available for economically providing hydro peaking power.

The existing combined pumped storage hydro projects include Rocky River, Connecticut (1929), Buchanan, Texas (1950), Flatiron, Colorado (1954), Hiwassee, North Carolina (1956), and Lewiston, New York (1961). Although of the same general type, these projects differ widely in design and operation. Figure 100 (in chapter 12) shows a photograph of the Lewiston project at Niagara Falls. This development is related to the international treaty governing flows over Niagara Falls. The treaty establishes minimum daytime flows over the falls of 100,000 cubic feet per second during the tourist season and minimum flows of 50,000 cubic feet per second at all other times. Flows in excess of these rates are divided equally between the United States and Canada and are available for generation of electric power. As a result, more water is available for power generation at night during offpeak periods when it is least needed. To take advantage of this, surplus nighttime flows are stored by low-head pumping for subsequent release through the pumped storage plant and then through the associated conventional hydro plant to produce power for daytime loads. A total of 2,194 megawatts of power is developed, an amount which is substantially greater than the capacity that could have been available without the pumping feature.

Pure pumped storage developments can have important advantages over pumped storage used in conjunction with conventional hydro, in that there is a wider selection of sites and the possibility of developing much higher heads, but normally this type of project will produce less kilowatt-hours and will be operated only to serve short-time peak loads. Since the same water is recirculated between reservoirs, pure pumped storage projects need not be located on large streams. On the other hand, combined pump storage projects normally have larger storage capacities. This provides greater flexibility in operation and permits more pumping on weekends when larger amounts of offpeak thermal capacity are available, as illustrated in figure 68.

The Taum Sauk project, Missouri, with a peaking capacity of 350 megawatts, is a typical example of a pure pumped storage peaking installation. It consists of a 50-acre basin constructed on the top of a mountain some 800 feet above the 370-acre lower reservoir. Make-up water for the project is supplied by the East Fork of the Black River which has a minimum flow of less than 5 cubic feet per second.

The Yards Creek project, New Jersey, with an installation of 337.5 megawatts is a pure pumped storage development now being constructed under license from the Federal Power Commission. A license has been issued to Public Service Company of Colorado authorizing construction of the 225-megawatt Cabin Creek project. Other projects under consideration include the Cornwall project, New York, with an initial installation of 1,800 megawatts, in which water from the Hudson River is to be pumped to a reservoir 1,100 feet above the river; the

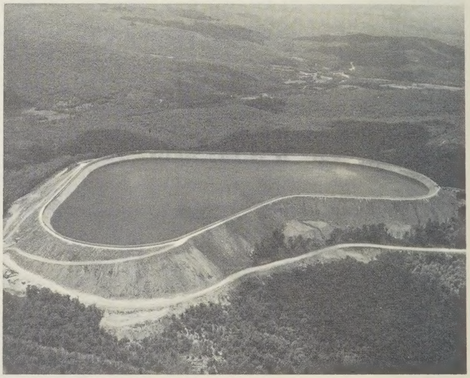


FIGURE 71 *The Taum Sauk Pumped Storage project includes a 50-acre upper reservoir on a hill some 800 feet above the lower reservoir. This project of the Union Electric Company, about ninety miles south of St. Louis, Missouri, has a generating capacity of 350,000 kilowatts.*

800-megawatt Muddy Run project on the Susquehanna River, Pennsylvania; and the 1,500-megawatt plant at Ludington, Mich.

The location of pumped storage projects at sites having high heads makes possible the installation of large capacity units with resulting low costs of construction and operation. The 175,000-kilowatt units at Taum Sauk are the largest capacity hydroelectric units in the United States. The units planned for the Cornwall project will be rated at 225,000 kilowatts.

Limitations of Pumped Storage Peaking Power

While pumped storage capacity is expected to increase materially in the future, there are a number of factors which will limit the total capacity which might be developed.

Pumped storage peaking projects are usually economical only when relatively high-head high-capacity projects are developed. They will, therefore, be restricted largely to those areas where the terrain is favorable and where they can be used in large interconnected systems.

Since energy for pumping must be transmitted to the pumped storage installation and the peaking energy must be transmitted to load centers, the distance of a proposed site from the source of pumping energy and load centers may place a limit on the economic advantage of pumped storage compared to alternate forms of peaking capacity.

There is ordinarily little need for development of pumped storage peaking capacity in systems which derive a large portion of their power supply from conventional hydroelectric sources, since peaking capacity can usually be obtained at low cost by planning adequate initial capacity or utilizing opportunities to add capacity for peaking requirements. In many instances, however, planners have not made adequate provisions for expansion of plant capacity to serve the peaks of expanded system loads that may occur in the next several decades.

There may be limitations on the availability of adequate supplies of low-cost pumping energy. As illustrated on figure 68, there are usually relatively few hours each week night when the more efficient baseload units are available to provide pumping energy.

Present and Prospective Pumped Storage Development

As shown in table 41, there are nine projects in operation or under construction with pumped storage combined with conventional hydroelectric developments. These projects will provide more than 800 megawatts in pumping units. An additional five combined projects with over 700 megawatts in pumping units are under active consideration. The inclusion of pumped storage in combination with conventional hydroelectric developments may frequently increase the economic size of the combined facilities by several hundred percent. The size of conventional plant reservoirs usually permits offpeak pumping to extend over the entire weekend period and thus the augmented water supply can have the effect of improving the dependable flow.

Table 42 shows that one pure pumped storage project is in operation and two others are under construction. These three projects will have a total capacity of about 1,100 megawatts. Fifteen projects under active consideration would provide an additional 8,600 megawatts of capacity.

Thus, there are a total of 32 pumped storage projects in operation, under construction, or under active consideration. The total installed capacity of pumping units in the 32 projects would be nearly 11,300 megawatts.

In addition, 69 other sites have been identified by various investigators as having features suitable for development as pumped storage projects. The estimated total capacity of all 101 sites, including those in operation and under construction, is 36,000 megawatts. Figure 72 shows the location of these 101 sites. The extent to which these and other potential sites may be developed by 1980 is discussed in chapter 15.

Steam Units Designed Specifically for Peaking

A few low capital cost steam-electric units of relatively low thermal efficiency have been built for use primarily on peak or as reserve capacity. Such installations are economical if the savings in first cost are enough to offset the cost of the resulting higher fuel consumption.

TABLE 41

Pumped Storage Combined With Hydroelectric Developments

Project	River	State	Installed capacity, (mw)	
			In pumping units	Total
In operation:				
Rocky River	Rocky	Connecticut	7.0	31.0
Flatiron	Big Thompson	Colorado	8.5	71.5
Buchanan	Colorado	Texas	12.5	33.8
Hiwassee	Hiwassee	North Carolina	59.5	117.1
Lewiston	Niagara	New York	240.0	2,194.0
Subtotal			327.5	2,447.4
Under construction:				
Smith Mountain	Roanoke	Virginia	132.1	432.2
DeGray	Caddo	Arkansas	28.0	68.0
Thermalito	Feather	California	60.2	92.0
Oroville	Feather	California	261.0	612.0
Subtotal			481.3	1,204.2
Under active consideration:				
Blue Ridge	New	Virginia	250.0	400.0
Kinzua	Allegheny	Pennsylvania	330.0	355.0
Moscow	Mississippi	Iowa	25.0	50.0
Joanna	Salt	Missouri	27.0	54.0
Meramec Park	Meramec	Missouri	81.5	365.5
Subtotal			713.5	1,224.5
Total			1,522.3	4,876.1

These machines are moderately large stripped-down steam-electric units, for operation at relatively low pressures and temperatures. Their capital cost is $20 to $30 per kilowatt less than the cost of standard baseload equipment. One manufacturer has recently offered a turn-key proposal to provide a complete peaking plant at a cost of $65 per kilowatt, exclusive of land costs and the utility's own overhead construction costs, in unit sizes from 135 to 400 megawatts.

The special peaking units are capable of being brought up to speed and synchronized in 10 to 15 minutes and fully loaded in 30 minutes from "hot bank." To avoid the investment costs of coal and ash handling equipment, these special peaking units would burn gas or No. 2 fuel oil. Since in many areas gas is not available for use as boiler fuel, and No. 2 oil is expensive (about 75 cents per million Btu), the fuel cost for these units would be high in those areas. The heat rate of the units would be about 12,500 British thermal units per kilowatt-hour at full load. By comparison, a heat rate of 9,000 British thermal units per kilowatt-hour or less is common for modern high-temperature high-pressure steam-electric generating units. Acceptance of these peaking units by the industry has been slow. With few exceptions to date, installation of more efficient units for base load operation has been generally more economical, the older less-efficient units being used for peaking.

TABLE 42

Pure Pumped Storage Developments

Project	River	State	Installed capacity, (mw)
In operation:			
Taum Sauk	E. Fork Black	Missouri	350
Under construction:			
Yards Creek	Yards Creek	New Jersey	338
San Luis	San Luis Creek	California	424
Subtotal			762
Under active consideration:			
Rowe	Kennebec	Maine	500
Deerfield	Connecticut	Massachusetts	300
Mt. Tom	Connecticut	Massachusetts	300
Cornwall	Hudson	New York	1,800
Breakneck	Hudson	New York	600
Longwood	Raritan	New Jersey	112
Tocks Island	Delaware	New Jersey	400
Muddy Run	Susquehanna	Pennsylvania	800
Rowlesburg	Cheat	West Virginia	380
Brookville	E. Fork Whitewater	Indiana	240
Ludington	Lake Michigan	Michigan	1,500
Chimney Rock	Grand	Oklahoma	480
White Oak	Arkansas	Arkansas	500
Petit Jean	Arkansas	Arkansas	500
Cabin Creek	S. Clear Fork	Colorado	225
Subtotal			8,637
Total			9,749

Steam Peaking Capacity Integral with Base Load Units

This area of steam plant design and operation has been thoroughly developed in recent years after experience demonstrated that many of the older steam units had substantial overload capacity. Further experience showed that such overload was safely usable in part for base loading, and in part for peaking or emergency use, the choice or dividing line depending upon close operational measurements of effect on equipment temperatures, pressures, metal stress, expansion, boiler slagging, and operating and maintenance costs. These studies and analyses resulted in new operating techniques, much new instrumentation, and new and more exact testing procedure.

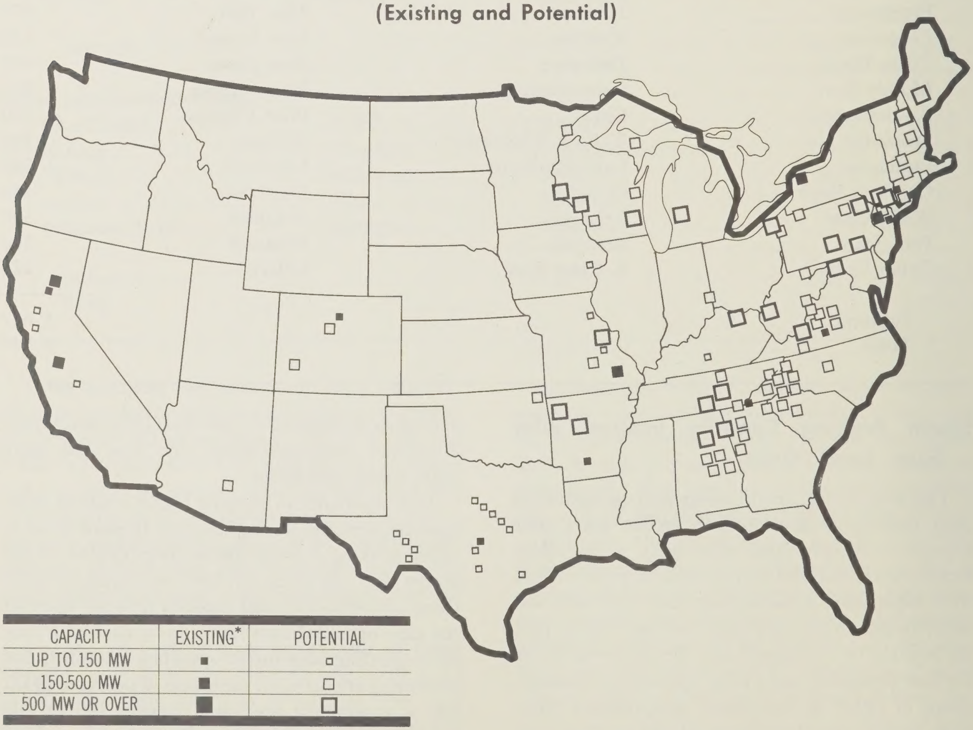
This experience in carrying higher loads on older units has resulted during the past 10 years or so in many peaking features being incorporated in the design and operation of new conventional units. Generally, efficiency and capacity tests are made at the time of initial installation to be used as a base for evaluating subsequent operating practices, and economics are based on the expected period of peaking or emergency operation, usually 100 to 200 hours per year. Consultants have advised, and operating experience of some utilities has demonstrated, that a substantial margin of capacity in excess of nominal rating is available in most steam turbines. Lower cooling water temperatures in the northern parts of the country permit operating at lower back pressures than the 3½ inches of mercury at which turbines are rated. Modern boilers are designed for 5 percent over pressure which can add from 4½ to 7 percent to turbine capability. Manufacturers conservatively design with some margin over the guarantee. This may be as much as 5 percent. Overall, these elements may contribute in the order of 10 to 12 percent to the capability of the turbine. To take advantage of them the generator should be sized accordingly. It should be pointed out, however, that turbines are being designed and rated nearer their ultimate capability than was the case some 20 years ago. For example, during World War II machines frequently were called on to deliver an output of 20 to 25 percent above rated capacity.

A distinction should be made between the foregoing peaking capacity in high-efficiency baseload units and the new-type spinning-reserve generating unit which has been developed. The latter combines the characteristics of a high-efficiency baseload generating unit with added short time capacity to be used during the daily maximum load periods. The peaking component of such a unit can amount to more than 30 percent of the unit's base rating. This added capacity is obtained through special features of design and operation.

The usual practice in the spinning-reserve generating unit is to bypass, or remove from service, high pressure heaters at peak load times. This results in higher flow of steam through lower stages of the turbines to the condenser, and higher capacity.

PUMPED STORAGE HYDROELECTRIC PROJECTS

(Existing and Potential)



CAPACITY	EXISTING*	POTENTIAL
UP TO 150 MW	▪	▫
150-500 MW	■	□
500 MW OR OVER	■	□

NOTE: *Includes Projects Under Construction as of January 1, 1964

Figure 72

However, additional capacity is obtained only with a sacrifice in efficiency, amounting to 15 to 20 percent when operating at maximum rating. For example, a unit having a base rating of 200 megawatts and a heat rate of 9,300 Btu per kilowatt-hour when operated at that capacity, would have a heat rate of about 11,000 Btu per kilowatt-hour when operated at maximum capability of, say, 270 megawatts. The net effect would be the addition of 70 megawatts of capacity at an equivalent heat rate of 15,857 Btu per kilowatt-hour. Because of the substantial sacrifice in efficiency, it is unlikely that the full peaking component would be utilized as a regular source of peaking capacity, each case depending on the economics. Instead, a substantial part would be retained as spinning reserve. With the unit already in operation, this spinning-reserve capacity would be essentially instantaneously available since its output could be increased at the normal rate for applying loads to conventional units.

Gas Turbines for Peaking

The simple open-cycle gas turbine-generator unit, as contrasted to the more efficient but more costly closed-cycle gas turbine, is attracting increasing attention as a possible source of economical peaking capacity and a significant number of these units are already so employed. It is low in first cost, relatively quick starting, offers wide choice of site location, and is readily automated.

Single unit plants of the simple open-cycle type are available in ratings up to about 30,000 kilowatts. These plants are pre-engineered and prepackaged to minimize field labor. Units in the order of 10,000 kilowatts are shipped assembled, but larger ones are erected in the field on concrete slab foundations. Typically, plants are furnished with a self-contained cooling system, and weatherproofed housings, and include provision for remotely controlled unattended operation.

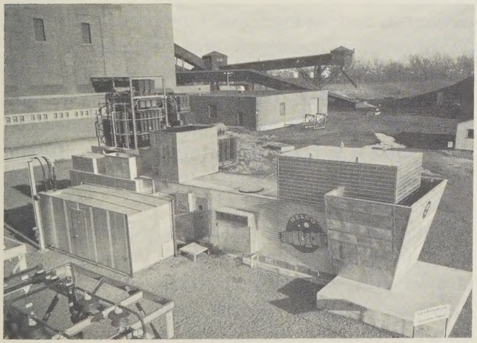


Figure 73 *Gas turbine peaking plants, such as this 10,000 kilowatt installation of the Hartford Electric Light Company, can be started, synchronized and fully loaded automatically in 5 minutes or less.*

Gas turbine units of larger ratings, employing several aircraft jet engines as gas generators, are now being offered by manufacturers. One design employs several jet engines in tandem—equally divided on either end of the centrally located generator. One of these units has been ordered by a large utility. It will have a rated capacity of 121,000 kilowatts and will be the largest gas turbine unit in the world. Another design consists of 10 cylindrically mounted aircraft gas turbines operating as gas generators exhausting simultaneously into a single-stage power turbine driving a 100,000-kilowatt generator. One of these units has also been ordered by a large utility system. A third design offers two conventional gas turbines for driving a single generator.

Principal Advantages of Gas Turbines

Gas turbine installations are relatively low in capital costs, ranging generally from $80 to $125 per kilowatt, depending upon type and size. The low cost results from the compact design, minimum number of station auxiliaries, low water requirements, and small foundation and building costs.

Units can be started, synchronized, and fully loaded in 5 to 20 minutes. This feature provides significant start-up and stand-by savings that must be considered when these units are compared to alternative steam peaking capacity.

Gas turbines, because of low investment cost and flexibility in location, are adaptable to a variety of peaking uses. These include standby reserve capacity, peaking capacity for small systems, interim peaking service for larger systems and interim capacity supply in extended areas of a system when also needed for load protection and to assure satisfactory voltage at times of maximum peak demand. Gas turbines provide system flexibility because they may be moved from one part of a system to another part, at small cost.

Principal Disadvantages of Gas Turbines

Gas turbines have low thermal efficiencies, requiring 15,000 to 18,000 Btu per kilowatt-hour of generation. They are limited to burning high grade liquid fuels or gas, which are costly in many areas. As a result, energy costs are high. In most cases, therefore, the use of gas turbines would be limited to annual plant factors not exceeding 5 to 10 percent.

The capability of a gas turbine decreases with decreasing density of its free air supply, so that its rating is influenced by the site altitude and ambient air temperature. The reduction in capacity with higher air temperatures may be of serious disadvantage for systems having summer peaks. Conversely, the capacity is enhanced at low temperatures, thus benefiting winter peaking operations.

Noise is a consideration which may preclude gas turbine plants at certain locations.

Diesels for Peaking

Diesel engines have been used for peaking on power systems for many years. The renewed interest in this type of peaking capacity has resulted primarily from the recent development of low cost, packaged, automatically operated, unattended diesel units.

Diesel units, while available in capacities up to 6,000 kilowatts, are usually manufactured in ratings of about 2,000 kilowatts and are frequently combined in multiples to provide plants of up to approximately 10,000 kilowatt capacity. Straight diesel, super-charged diesel, or dual-fuel engines are available. A single engine and generator are usually mounted on a structural steel base and enclosed in a sound suppressing and weatherproof housing, together with lubricating and cooling equipment, and other accessories. Automatic control equipment is brought together in a separate control cubicle. These packaged units can be shipped on freight cars or trucks to the site and installed outdoors, requiring very little foundation work.

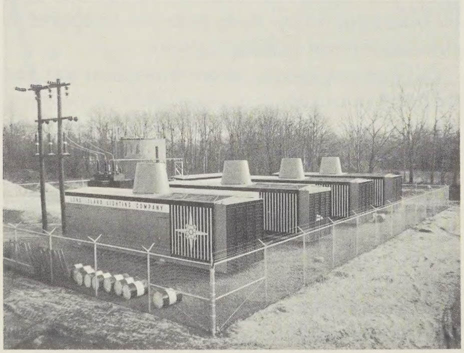


FIGURE 74 *Diesel peaking installations such as this group of 2,000 kilowatt generating units have the advantage of mobility in the interim strengthening of outlying weak areas where small increments of capacity will suffice.*

Many of the operating and economic features of the diesel peaking unit are similar to those characteristic of the gas turbine, but there are significant differences. The capital cost of larger diesel installations is about $100 per kilowatt and the heat rate is about 12,000 Btu per kilowatt-hour. Diesel units have the outstanding ability to accept full load from cold startup within 60 to 90 seconds. They are well suited to part-load operation and can furnish spinning reserve service.

On major power systems diesels are not widely used for peaking capacity, since available sizes are too small. They are sometimes installed for the primary purpose of deferring investment in transmission facilities. Since these units can be readily and cheaply moved, they could serve this purpose in many different locations on a system over a period of years. Such applications would ordinarily be expected in areas of relatively low load density and growth rate.

Summary and Conclusions

A wide variety of low capital cost peaking facilities is available for selection by system planners. As new efficient baseload plants are added, existing thermal capacities will be reassigned, the less efficient units moving higher into the peak of the load. Modification of reassigned units may often be justified to improve their peaking capacities and reduce operating expenses. Most base load steam units have a margin of 10 to 12 percent above rated capacity, and it is likely that utilities will be making more use of this overload capability for peaking and for spinning reserve.

Some new steam units will be especially designed for peaking service but the lower investment cost of these units will be offset by higher operating cost. However, relatively limited application of these units is anticipated, especially in coal-burning areas.

Hydroelectric installations will be expanded at many existing plants and new installations will be planned with larger peaking capacities. Where physical conditions are favorable for economic development, pumped storage will be utilized to an increasing degree in serving peak loads.

The recent introduction of multiple jet engines in the gas turbine field has greatly increased the capacity of gas turbine plants and broadened the opportunities for their economic application. Diesel engines, in packaged multiple units, will find some application among the smaller systems for meeting special peaking needs, some on an interim basis. Aggregate capacities of gas turbines and diesels will be relatively small.

Most equipment installed specifically for peaking service will be largely automated, requiring little manpower for operation. The proper selection of peaking capacity depends upon many factors such as those related to system size, type of facilities, availability of fuels and opportunities for coordinating peaking capacity with other systems. Each decision must be justified on the basis of evaluating all of the conditions attending the particular situation. There is no rule of thumb broad enough to render individual analysis unnecessary.

CHAPTER 8

POSSIBLE NEW METHODS OF POWER GENERATION

Simpler and cheaper methods and equipment for generating electricity are challenging goals. Modern steam-electric stations involve massive equipment, temperatures above 1,000 degrees Fahrenheit, pressures as high as 3,500 pounds per square inch, and rotational speeds up to 3,600 revolutions per minute. For many years engineers and scientists have studied the possibilities of generating electricity with less complex devices.

The basic principles which would permit technical achievement of this objective have been known for many decades, but the outlook for their economic utilization has not been considered promising. More recently the need for power plants for space and special military applications has resulted in the channeling of much research and development effort into these areas of electricity production. The general objective has been to produce a light, long-lived, and perhaps noiseless power plant which could operate with little or no maintenance.

Three of the approaches being most actively pursued include: (1) the thermoelectric generator, (2) the thermionic generator, and (3) the fuel cell. None of these would require moving parts and hence hold promise of long, maintenance-free operation. They suffer the common disadvantage of producing direct current electricity in small quantities and at very low voltage, in the order of 1 volt. While the output can be converted to alternating current, the conversion equipment will cost some $40 per kilowatt.

There are two other approaches, and these appear to show more promise for generating electricity on a commercial basis. One employs the principles of magnetohydrodynamics, frequently abbreviated as MHD; the other is controlled nuclear fusion reaction. These latter two approaches are not limited to production of electricity at low voltage, and there is some prospect that the output would not necessarily be direct current.

These five concepts are described in some detail below, borrowing heavily from Advisory Committee Report No. 8 on New Methods of Power Generation, prepared by a subcommittee of the Generating Stations Special Technical Advisory Committee.[1]

Thermoelectric Generation

Thermoelectric generation, illustrated schematically in figure 75, makes use of a principle established over 100 years ago. When heat is applied to one of the joined ends of two dissimilar conductors, the electron activity will be increased more in the material of one conductor than the other, so that a potential difference will be produced. The thermocouple is a well-known example of a device based upon this so-called "Seebeck" effect. Clearly, if large currents are to be produced, the materials forming the junction must be good electrical conductors. This creates a problem because usually good electrical conductors are also good heat conductors, so that heat applied to the junction tends to be conducted away and wasted. Advances in solid-state physics in recent years have made possible the development of semiconductors which permit considerably improved efficiencies over those achieved theretofore with metallic type junctions. To obtain appreciable amounts of power, the coupling together of a large number of junctions is required.

Thermoelectric generators have been built and operated successfully for moderately long periods of time. Such generators, heated by radioactive isotopes, are being used for military and space applications to provide remote unattended power sources. Thermoelectric generators burning hydrocarbon fuels have been built with capacities ranging from a few watts to 5 kilowatts. Present problems are life of thermoelectric elements, heat transfer, and low efficiency.

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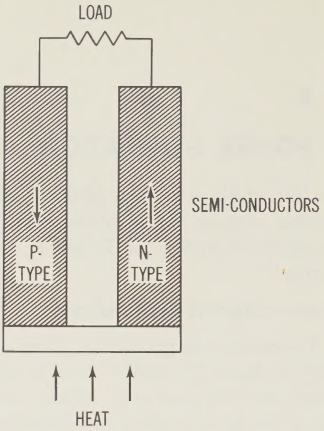
[1] The Advisory Committee states in its report that all information on timing, performance and estimated costs was obtained from manufacturers and research organizations knowledgeable in these concepts.

THERMOELECTRIC GENERATION



Based on Advisory Committee Report No. 8

FIGURE 75

Some applications for thermoelectric generators have been predicted by 1980 in sizes up to 200 kilowatts. However, it appears that the overall efficiency for thermoelectric generation may be in the order of 10 percent. If so, this will eliminate thermoelectric generation for central station use.

Thermionic Generation

Thermionic devices depend on the phenomenon known as the "Edison effect" (the emission of electrons by metals at high temperatures). The existence of this phenomenon was established in 1878 by Thomas Edison. The conventional heated filament vacuum tube is one application of thermionic emission.

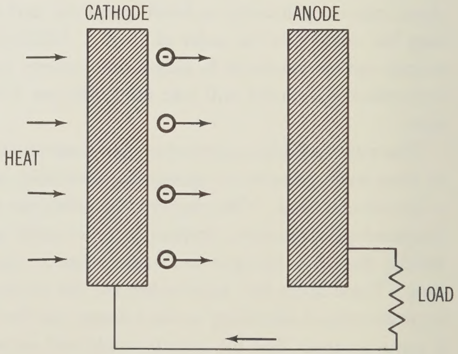
As indicated schematically in figure 76, a thermionic generator contains an electron emitter, called the cathode, which is heated. Heating causes electrons to "boil off." These electrons have enough momentum to move through an intervening space to a cooled electron collector, known as the anode. The electrical potential so created can cause a current to flow in an external load. The hot cathode also radiates heat to the collector, and this represents a loss in efficiency. For this reason high current flow between cathode and anode (high power output) is desired to hold radiation losses within a reasonable proportion of the energy input. However, the current flow tends to be limited by the "space charge" of electrons that build up around the cathode. This effect may be minimized by making the gap between cathode and anode very small, or by neutralizing the space charge with a material such as caesium which is ionized at the operating temperatures. Experimenters now seem to favor the neutralizing approach over the "narrow gap" approach.

Thermionic generators combining satisfactory operating and economic characteristics have not yet been developed. The major problems involve emitter materials and fabrication.

The desirability of high cathode temperatures (3,000° F.) suggests the eventual possibility of using a nuclear reactor as a heat source, even though such temperatures are not practical today. Designing thermionic generators as an integral part of nuclear reactor fuel elements promises the highest performance and most compact nuclear powered units. However, the problems are compounded when the emitter must also serve as a nuclear fuel element, and the collector, its heat baffles and its cooling system must be built of materials which do not absorb an excessive fraction of neutrons and can withstand the intense nuclear radiation. Such assemblies also must be reliable enough in large numbers that excessive reactor shutdown time is avoided.

Hydrocarbon-fueled thermionic generators are also feasible; however, considerations of heat transfer and combustor performance limit their overall efficiency to perhaps less than half that theoretically possible with reactor fuel element generators.

THERMIONIC CONVERSION



Based on Advisory Committee Report No. 8

FIGURE 76

It is predicted that by 1970 there will be limited space applications of thermionic generators in sizes up to 100 kilowatts, and, by 1975, larger demonstration units may be available. Through anticipated improvements in technology, especially in the fabrication of thermionic elements for use in nuclear reactors, 100 megawatts thermionic reactor units may be "topping"[2] the steam cycle in nuclear plants—conceivably by 1980.

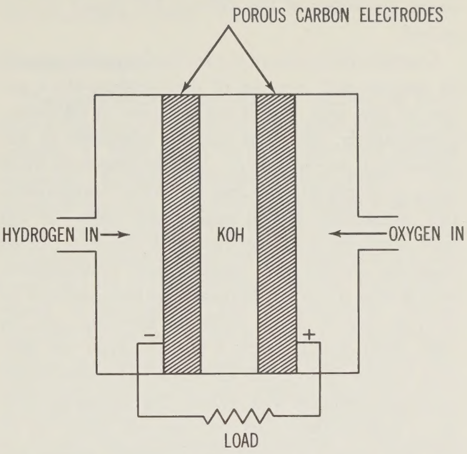
The efficiency of thermionic converters is presently under 10 percent but may ultimately be as high as 30 to 40 percent. Moreover, using them in conjunction with conventional steam cycles might result in increasing nuclear steam plant efficiencies by as much as 15 percentage points. It is estimated that in 1970 thermionic generator costs will still be well above $1,000 per kilowatt, but that by 1980 costs could be reduced appreciably, possibly to $200 per kilowatt.

Fuel Cells

Fuel cells have been known for more than a century. They are electrochemical devices in which chemical energy of oxidation of conventional fuels is converted directly into low voltage direct current without the use of a heat engine cycle. Fuel cells have the basic elements of a battery—positive and negative poles, and an electrolyte—but, unlike batteries, the energy to be converted is not stored in the cell. In any type of fuel cell, it is necessary to combine the fuel, such as hydrogen, with the oxidant, either commercial oxygen or air. The driving force that keeps the fuel cell operating is the free energy of the chemical reaction. The chemistry of the hydrogen-oxygen cell, for instance, is basically as follows: at the oxygen electrode, hydroxyl ions are formed by removing electrons, thus leaving the electrode positive; at the hydrogen electrode, hydroxyl ions combine with hydrogen to form water, giving off electrons in the process. Consequently, the hydrogen electrode becomes negatively charged with respect to the oxygen electrode, and a current can be made to flow through an external circuit. The principle involved is indicated in figure 77.

Many types of cells are being investigated, encompassing a wide range of temperatures and pressures. Present attempts to use hydrocarbons directly have met with little success. Reforming light hydrocarbons and feeding the by-products to the cell as a fuel has been suggested as a possible solution to the problem. Both low and high-temperature solid electrolyte fuel cells show promise. The solid electrolyte, high-temperature cell operating at 2,000° F., appears capable of using directly any fuel, including coal.

HYDROGEN-OXYGEN FUEL CELL



Based on Advisory Committee Report No. 8

FIGURE 77

Fuel cells which produce electricity through oxidation of hydrogen or hydrocarbon fuels are not limited to Carnot efficiencies.[3] There is also a class of fuel cells in which the chemicals used to produce the electricity may be thermally regenerated and recycled through the cell. This type of cell could be operated in conjunction with a number of different heat sources, including the nuclear reactor. The thermally regenerative fuel cell is limited to Carnot efficiency, but overall efficiencies of up to 40 percent may be expected.

Fuel cells operating on pure hydrogen and oxygen are currently being used in a few limited military and space applications. Hydrogen is an expensive fuel and fuel cells are neither economically competitive with commercial power sources nor commercially available in large sizes at the present time. The earliest commercial applications appear to be as mobile power sources. Possible industrial applications are in the electrochemical industries where quantities of low-voltage DC power are required.

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[2] Serving as a supplemental heat source to increase steam output.

[3] Theoretical maximum efficiency of conversion of heat to work, which is set by the upper and lower temperatures of the conversion process.

Overall efficiencies of the fuel cell could approach 60 percent and, because of the building-block nature of fuel cells, size is not a factor in efficiency. Consequently, fuel cells may be adaptable to dispersion on a power system. This development could have an important bearing on future transmission and distribution system design and costs. It has been predicted by some that, with the effort being expended in fuel cell research and development, cells in sizes up to 100 kilowatts will be available by 1975 at costs of about $200 per kilowatt, and, by 1980, costs should reach a level of $100 per kilowatt in sizes up to 1,000 kilowatts. However, present studies indicate that, at best, the net energy costs for a hydrocarbon fuel cell are not likely to be less than those for conventional central station operation. Therefore, by 1980, the fuel cell is not expected to be a source of central station power.

MHD Generation

Magnetohydrodynamic generation of power is based on the same principle as conventional generation. Instead of a solid conductor moving across a magnetic field, a jet of ionized gas is forced through the magnetic field. By placing electrodes in this gas stream, direct current electricity at relatively high potential, e.g., 2,000 volts or more, can be obtained. This principle is shown schematically in fiigure 78.

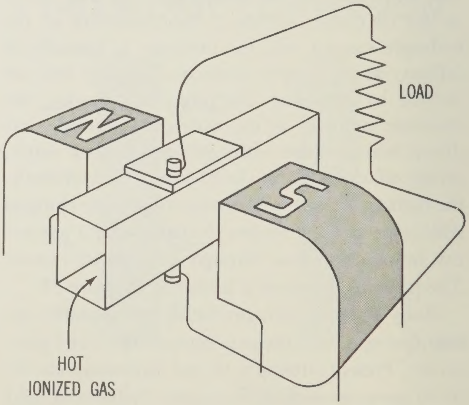
The generation of electric power by MHD principles has been demonstrated in a number of laboratories. Operation of small MHD units (at zero power level) for as much as 100 hours has been claimed, while power outputs as high as 11,200 kilowatts for short periods have been reported. However, the attainment of a practical MHD generator is still a major challenge. A basic problem is obtaining sufficient ionization, or electrical conductivity, in the gas stream for large currents to flow. This has required heating the gas to very high temperature—perhaps 5,000° F. Intense magnetic fields also are needed. All tests have clearly shown that the required high temperatures create a serious materials problem, both for the electrodes and the gas duct lining. Recent developments in superconducting magnets permitting fields of 100 kilogauss have enhanced the prospects for MHD generation. Nonthermal methods for ionizing gases have also been reported which might allow lower gas temperatures. If these methods prove feasible, the problems might be alleviated and MHD development hastened.

Because of the high temperature of the exhaust from the MHD device, and for other technical and economic reasons, MHD units combined with a steam cycle appear more practical for central station generation than the MHD generator used alone. There are differences of opinion as to the more promising way to utilize MHD generation—through the closed cycle nuclear approach, or through the open cycle fossil fuel approach.

Since temperatures in the range of 3,000° F. would be required using normal gas ionization, or 2,500° F. using nonthermal ionization techniques, much development would be required to advance the temperatures in a closed cycle nuclear reactor above the 1,340° F. temperature in present gas cooled reactors.

It appears that a high temperature fossil fuel technology exists for the open cycle fossil fuel approach and there is a greater latitude in the selection of high temperature resistant materials. However, in addition to the development problems of the MHD generator itself, there are other significant problems with the open cycle coal fired MHD unit. For instance, the requirement of oxygen en-

MAGNETOHYDRODYNAMIC (MHD) GENERATION



Based on Advisory Committee Report No. 8

Figure 78

richment to achieve required high temperatures results in a strongly oxidizing atmosphere, which will require costly materials to withstand. Molten coal ash and added alkali seed material create problems in both the MHD system and the following conventional steam generator. The need to recover 99 percent or more of a costly seed material is an added complication.

An MHD generator is uniquely a bulk power generator, and, when combined with a conventional steam plant, will be best suited for plant sizes ranging from 300 megawatts to over 1,000 megawatts. MHD generators can achieve an overall efficiency in the range of 55 percent to 60 percent. They would provide a major breakthrough in steam plant efficiency as compared with conventional units whose efficiency inherently is limited to approximately 40 percent. The large savings which MHD generators could provide is demonstrated by the fact that heat rates of 6,000 Btu per kilowatt-hour could be attained compared with a design heat rate of 8,250 Btu per kilowatt-hour in the best of conventional units.

Of all the newer potential techniques for central power generation, and despite its many problems, MHD is viewed with the greatest optimism by many utility people. Nevertheless, it is not expected that MHD will contribute appreciably to the Nation's power supply by 1980.

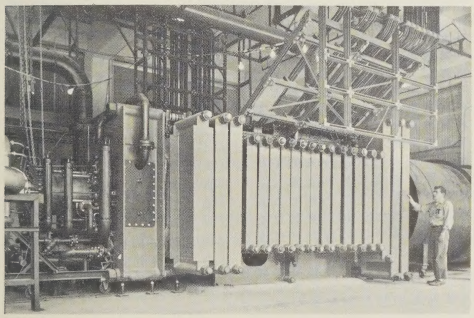
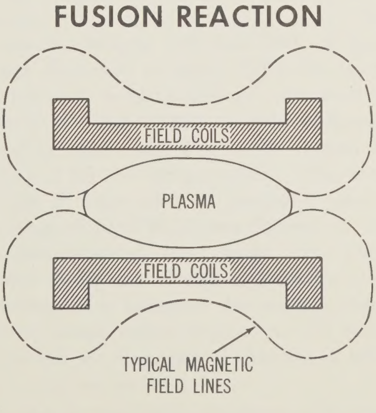


FIGURE 79 *The Mark V MHD 20,000 kilowatt direct current generator undergoing stage testing at the AVCO-Everett Research Laboratory at Everett, Massachusetts, has attained a power output of 11,200 kilowatts on June 18, 1964 at the end of a 55 second test run. This project sponsored by the Advanced Research Projects Agency of the Defense Department has a combustion chamber, shown on the left, which burns a mixture of gaseous oxygen and ethyl alcohol seeded with potassium hydroxide, and is designed to operate at a maximum combustion pressure of eight atmospheres and a maximum mass flow of 132 pounds per second.*

Fusion Reactor

Thermonuclear fusion consists basically of combining the atomic nuclei of very light elements by collision at high speed to form new and heavier elements. Energy is released in the process. The speed of random nuclear particle travel is a function of temperature. The speeds needed for thermonuclear fusion correspond to temperatures in the range of 40 to 100 million degrees Fahrenheit, which is far above the temperatures (about 100,000° F.) at which the hydrogen, deuterium, or tritium gas molecules have been disassociated into individual atoms and the orbital electrons have separated from the nuclei. Such a random mixture of nuclei and unattached electrons is commonly called a plasma and can be considered as a fourth state of matter. It is an excellent electrical conductor.

Since solid materials do not exist at such temperatures, concepts for thermonuclear reactors are based on the use of magnetic fields to contain the hot plasma of nuclear particles. A schematic illustration of a fusion reaction contained by a magnetic field is shown in figure 80. It appears possible that some of the energy released in fusion may be recovered directly as electric energy. Recent work on fusion reactions has been encouraging. Neutrons from thermonuclear reactions are being ob-



Based on Advisory Committee Report No. 8

FIGURE 80

served in the laboratory. The research programs of each of the Atomic Energy Commission laboratories, of National Aeronautics and Space Administration, Department of Defense, and National Science Foundation contractors, and of industry are contributing toward understanding the complex behavior of plasmas.

The threshold of fusion power, using a mixture of deuterium and tritium, is said to be 40 million degrees Centigrade for 1 millisecond. The immediate problems needing solution are containment and temperature. However, it has been stated that fusion technology has not yet reached the 1942 level of fission technology. Further, it has taken 20 years to construct feasible bulk power stations using fission reactors. On this basis, practical fusion power generation does not seem probable by 1980.

The practical development of fusion power would seem to make available inexhaustible energy resources. The oceans contain virtually unlimited quantities of heavy water which can be recovered for about $20 a pound. At such a figure, the expected fuel cost for a thermonuclear reactor would be around 0.2 mill per kilowatt-hour. Also, unlike today's nuclear reactors, thermonuclear reactors do not produce the extremely troublesome radioactive fission products that present difficult disposal problems and more importantly their fuel supply would be virtually unlimited.

In view of these potentials, it is expected that work on fusion power will be continued and that it must be considered a serious contender for a major role in power development of the more distant future.

Conclusions

Assuming continuing developmental effort, the following predictions are warranted:

- Power generation by each method, except fusion, will be technically feasible by 1980.
- The first practical application of these new methods will be for defense and space requirements where each method offers specific advantages, such as the elimination of moving parts, reduced weight, and feasibility of unattended operation. Wider applications will follow where specific user advantages will outweigh unfavorable costs.
- Because of the extended time expected to be required for developing these applications, their use in central stations by 1980 will be negligible.

CHAPTER 9

AIR AND WATER POLLUTION AT THERMAL-ELECTRIC GENERATING PLANTS

Environmental considerations will become increasingly significant factors in the location, design, and operation of future thermal-electric power plants, as the size of plants and their output increase. The problem of air pollution and thermal pollution of water will be of particular concern at most future installations. The industry's vigilance in planning these large installations and incorporating the proper measures to minimize pollution will be the subject of increasing public concern. The electric power industry has long recognized these problems and has spent large sums for research and control of air pollution.

As a result of past research and observation programs, the potentially damaging thermal, particulate, and gaseous discharges from thermal-electric power plants have been identified and measured. Their magnitude can be predicted within relatively close limits for any given set of fuel and operating conditions. The significant types of potential damage have also been identified in laboratory and field studies. Generally speaking, however, the physical and economic consequences of the various pollution potentials have not been established to a degree of precision that would warrant their use as more than a guide to power station planning. Work currently underway by private and public groups is continually adding to the conclusive information on the subject, but it will probably be several years before definitive criteria are available.

Water pollution problems associated with thermal-electric power plants are almost entirely limited to those that result from the temperature rise in surface water supplies that are used for cooling the steam condensers of both fossil-fueled and nuclear-powered units. The term "thermal pollution" is popularly used to identify this aspect of the total water pollution problem, although heating is not pollution in the usual sense. Air pollution associated with power plants stems from the particulate matter and gases emitted by furnace stacks of fossil-fuel plants. The reactors at nuclear-powered generating plants are completely enclosed and controlled, and under normal operating conditions these plants create no problems of air pollution but they do heat the condensing water somewhat more than conventional plants of the same size due to the relatively lower operating efficiencies of present-day nuclear plants. The confinement of radiation at nuclear stations is discussed in chapter 5.

Thermal Pollution

Thermal pollution in surface water supplies has historically been of little general significance in the United States. However, as the use and re-use of water for industrial and other purposes increase, the problems of thermal pollution become more important. Thermal-electric power plants are of particular concern because of the large quantities of heat they release to cooling water, and the heat concentrations that will be associated with the tremendously large plants envisioned for the future. An offsetting factor, however, is the fact that increased efficiencies of modern plants reduce their thermal pollution potential. In 1962, the average fossil-fueled power plant in the United States required about 10,550 British thermal units (Btu) of heat input to produce one kilowatt-hour of electrical energy. It is expected that the plants that will be installed between 1970 and 1980 will have an average heat-rate of about 8,500 Btu/kwh. This improvement in plant efficiency will result in a decrease in the amount of heat to be dissipated to the cooling water, and thus in the amount of water required for the cooling system. The temperature rise in water used for cooling is usually within a range of 10 to 20 degrees Fahrenheit, depending upon individual plant design. The average is about 13 degrees. Based on a continuation of this average, it is estimated that cooling water requirements would reduce from about 1.5 cubic feet per second per megawatt of capacity in 1962 to about 1.2 cfs/mw in 1980.

The additional transmission interconnections that are anticipated for the future should also provide advantages for pollution control. In emergency circumstances where stream-flows or other cooling-water supplies are critically low at one plant, it may be possible to supply the load by increasing generation at some other plant in the interconnected system where water supplies are adequate, thus avoiding critical temperature rises in the cooling water body in the low-flow areas.

In general, the effects of thermal pollution stem directly from the rise in temperature of the water and the decrease, resulting from the temperature rise, in the capacity of the water to hold dissolved oxygen. The resulting changes may influence the aquatic life of the water body, its waste assimilation capacity, and the value of the water for municipal, industrial, and recreational uses. The magnitude of these changes is, of course, inversely proportional to the size of the receiving water body. The significance of the effects depends on the degree and type of subsequent uses to be made of the water supply. Research will be needed to predict accurately the effects of a given plant on a given stream.

Thermal Pollution in Streams

Temperature rises in streams are generally dissipated rapidly, so that the measurable effects of adding heat to the water are usually small at points only a few miles downstream. The number of streams with flows of the magnitude required for the large plants of the future are not numerous, however, and re-use of major streams for power and other industries using large volumes of water will be increasingly necessary. The water requirement figures discussed in the preceding section show that stream diversion needs would range from 1,200 to 6,000 cubic feet per second for 1,000 and 5,000 megawatt plants, respectively. Using the general criteria of limiting cooling water diversions to one-half the stream flow, plants of such size using stream cooling water supplies would be limited to streams having minimum flows of 2,400 to 12,000 cubic feet per second. Streams of such size almost invariably are used extensively for other industrial and municipal purposes that contribute heat or other pollutants to the water body, thus adding to the problems of future power plant development.

Fortunately, river basin development programs underway and planned generally provide storage to augment flows during critical periods, thus increasing the miles of stream in the nation with reliable flows large enough to provide cooling water for relatively large thermal-electric installations. Even with the extensive river basin developments now envisioned, however, proper spacing of all sources of thermal pollution of streams will be an increasingly significant factor in future power plant location.

Streams are capable of assimilating some quantities of municipal sewage and most other liquid wastes and of purifying themselves, because normal biochemical processes in the streams decompose the wastes and gradually convert them to simple, innocuous compounds such as carbon dioxide, nitrates, and water. Oxygen dissolved in the water, and harmless bacteria found in every surface stream, are essential to the decomposition process. The biochemical reactions and the rate of oxygen used are speeded up by higher water temperatures. If the rate of natural reaeration in the stream is too low to keep up with the oxygen demand, oxygen concentrations may decrease to the level where fish die, the water becomes septic, the stream turns dark in color, and unpleasant ordors are produced. Increases in temperature decrease the saturation capacity of the water for dissolved oxygen but increase rates of reaeration. Thus, the net assimilative capacity of a stream may be reduced in reaches where large amounts of heat are transferred to relatively small flows of water, or it may be increased under some circumstances. Precise determination can be made only after specific information has been assembled for the situation under study.

Most species of fish and the aquatic plants and animals on which they feed are affected by the temperature of their water environment, and each has its tolerance range. While tolerances vary with environmental circumstances, 93 degrees F. is often considered the maximum water temperature at which a satisfactory warm-water sports fishery can be maintained. Cold water fish, such as trout, have substantially lower tolerance limits, and require a plentiful supply of oxygen at temperatures near the tolerance limits. Long range temperature changes in a stream or reservoir usually result in increases of some types of plant and animal life and decreases of others. These effects may reach far beyond the immediate species affected, in that the elimination of one species in the food cycle may upset the ecological balance.

The addition of heat to streams affects fish adversely when the thermal tolerance limit for the fish is exceeded, even for a short period of time; the dissolved oxygen supply is reduced to levels which restrict feeding, reproduction activities, or metabolism; or the environmental change eliminates a major component in the fish food chain. Also, the tolerance of fish to toxic substances generally decreases as water temperature rises.

Algae are a problem in many streams, with the detrimental effects varying widely with stream conditions. In nonpolluted streams algal growth is usually limited by the availability of a vital nutrient such as nitrogen or phosphorous. In these nutrient deficient streams, a thermal increase will have relatively little effect on algal growth. Cold water streams, however, may be polluted but free from algae because temperature rather than nutrients is the major limiting factor. In such cases algal growth will increase significantly if the water temperature is raised. Excessive algal growth may be expected in areas where a thermal increase occurs in combination with an enriched environment such as in the recovery zone downstream from a source of domestic pollution. The types of algae may also be expected to change with temperature variations. In the range of 95° to 100° F., the blue-green types tend to become predominant, and these generally produce taste and odor problems in water supplies. Thus, heat additions to a stream can have effects on algal growth which may be detrimental to water quality.

Warm water is less acceptable for drinking and household uses, and may also be less satisfactory for industrial uses. For water-cooled air conditioning, for example, the volume of water used on peak days increases about 5 percent with each degree of temperature rise in the basic supply, thus increasing costs. The adverse effects of thermal pollution of streams on recreation may deter swimming, aquatic sports, and fishing. Fog rising from heated water bodies may have some objectionable effects.

The proper location of thermal-electric plants with regard for the effects of the discharge of condensing water depends on downstream water uses of other industries and many other factors. Probably the most important consideration is the proportion of total stream flow diverted through the condensers. If only a small portion of the stream flow is diverted as cooling water, the effect on the stream will be very minor. Potential damage to aquatic life, and to downstream uses, increases as the relative flow through the condensers increases. In any case, provision should be made, after consultation with public health and fishery authorities, to insure that the maximum stream temperature determined to be reasonable in the light of local conditions is not exceeded.

It appears that on major rivers—even highly industrialized streams such as the Ohio—a large amount of additional thermal-electric capacity can be installed if proper attention is given to spacing the plants in relation to one another and to other sources of thermal pollution. Economic considerations tend to induce proper spacing because warm intake water for the condensers reduces the efficiency of cooling systems.

Thermal Pollution in Ponds, Lakes and Reservoirs

When heat is continually added to water in ponds, lakes, or reservoirs, the rise in temperature increases the heat released from the water due to convection, radiation, and evaporation. Eventually, a point of equilibrium is reached, but at a higher pond water temperature than would prevail without the heat addition. The net rise in temperature depends upon the heat input, surface area and volume of the reservoir, inflow and outflow of the reservoir, meteorological conditions at the site, and other factors, all of which are variable. The result of using an impounded water body for cooling water in a thermal-electric power plant therefore varies from place to place, and from day to day at any given location.

The significance of thermal pollution in reservoirs is more-or-less directly associated with the uses that are to be made of the impounded water. If the storage is provided exclusively for condenser cooling, the permissible temperature rise is limited only by the desired cooling water inlet temperature, the desirability of limiting algal growth or other water contaminants that might cause operating problems in the cooling system, and the effects of reservoir discharges on downstream areas. If other uses of reservoir water are anticipated, the problems are generally similar to those discussed above for streams.

Comparatively little is known about the circulation of water in large water bodies that results from temperature differentials. It is known that in an open lake or pond added warm water tends to spread quickly over the whole water body, and that water in the pond tends to stratify in layers of varying temperature. Studies have also shown that the

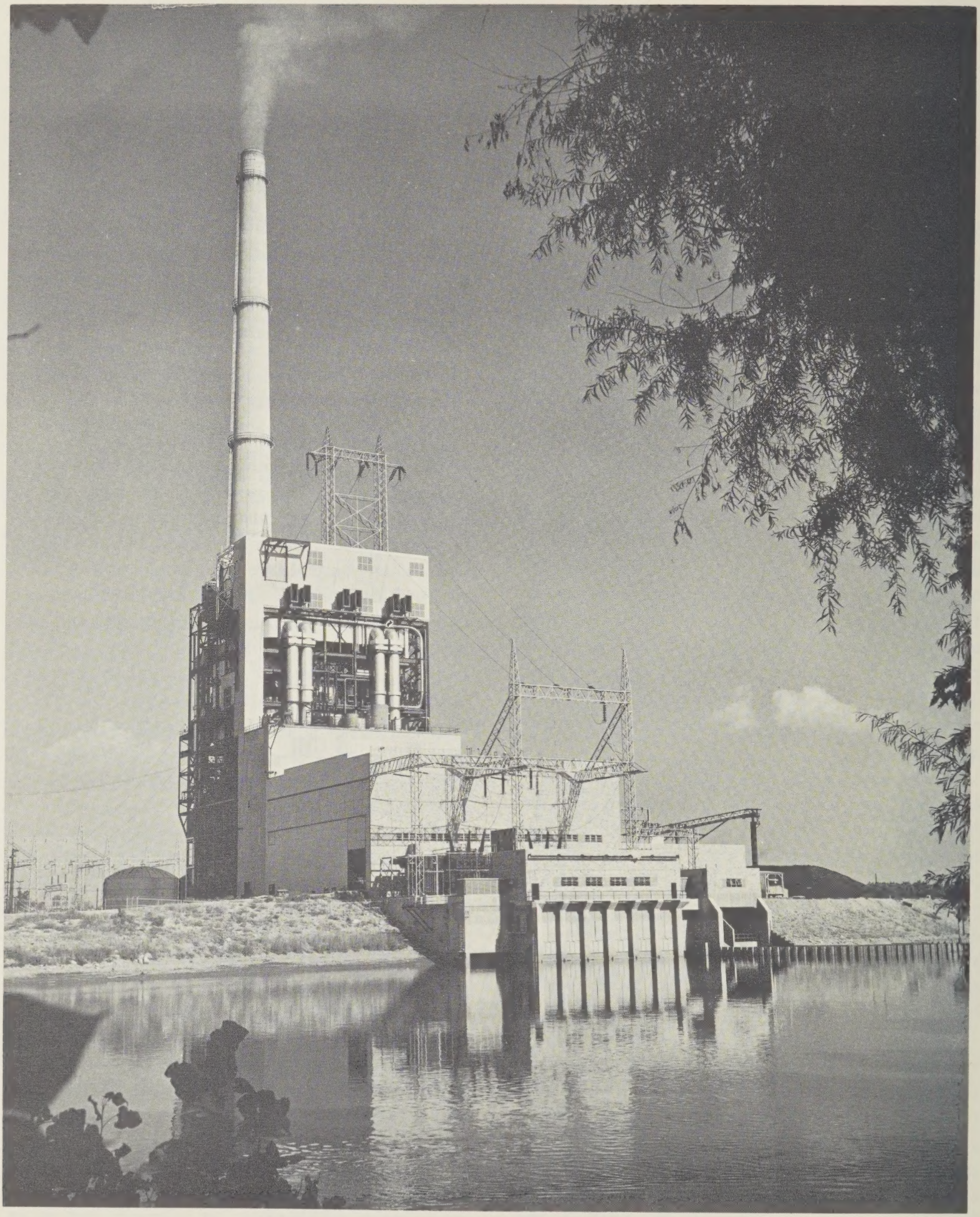


FIGURE 81 *A single 500,000 kilowatt unit, the first of its size in the nation, is housed in the Breed Plant of the American Electric Power System at Sullivan, Indiana. Its location on the banks of the Wabash River provides immediate access to condenser cooling water.*

area of high-temperature water around the discharge point is relatively small.

Intake structures are usually constructed to permit drawing the cooler water from the lower elevations into the cooling system. Skimmer structures have been built in at least one location, TVA's Kingston Steam Plant, to keep the warm water at the top of the reservoir from entering the forebay serving the cooling system pumps and thus take advantage of the phenomenon of stratification to obtain cool condensing water. The use of the cooler water improves the cooling efficiency. It also may reduce the temperature of the discharge water and therefore be beneficial from the thermal pollution control standpoint.

In irregularly shaped water bodies, the dispersion of heated water released from condensers is limited in some degree by the bay or arm in which the heated water is discharged. Thus all of the surface area of an irregularly shaped reservoir does not contribute equally to the cooling process. There may be advantages, however, from limiting the area in a reservoir affected by thermal pollution. A substantial heat rise might be tolerable, or even be beneficial, in some selected part of a large reservoir if the rise in other areas is limited. Research is needed to substantiate and expand the information now available on the subject.

Air Pollution

Fossil-fueled power plants consume over one-sixth of the energy released by the combustion of coal, fuel oil, and gas in the United States, but they do not contribute proportionately to the Nation's air pollution problems because the electric power industry has taken a leading role in pollution control. Nevertheless the tremendously large power furnaces of the future will have pollution concentration problems not faced in the past, and not common to most industries. In some instances potential air pollution problems may have a decisive influence on power plant locations, and they will have an important effect on operating procedures at every large installation.

Types of Air Pollutants

Air pollution is considered to be a problem when the combinations, concentrations, and time-durations of foreign substances in the atmosphere are such that normal plant life, animal life, or human health is affected, significant damage to property occurs, or nuisance conditions are created. Broadly classified, air pollutants consist of particulate matter and gases. Those of major concern at fossil-fueled power plants include fly ash and poly-cyclic hydrocarbons in the particulate group, and the oxides of sulfur and nitrogen in the gases.

The damages resulting from fly ash and other solids are usually related to the soiling of surfaces, limited visibility, and annoyance to the senses of people. In addition, the finer particulates are of public health concern because the human respiratory system tends to remove them from inspired air and retain them in the lung. Some mineral particulates have a demonstrated ability to increase oxidation rates, thus hastening the conversion of dioxides to the more damaging trioxides and acids. Also, some poly-cyclic hydrocarbons (which are at a minimum in efficient steam plants) are known to have cancerigenic properties.

A widely varying part of the ash content of coal is retained in the furnace chamber as fluid slag or solids, depending on the fuel and the design of the furnace. Most of the fly ash escaping to the stack area is removed from flue gases by any of several varieties of mechanical separators and electrostatic precipitators. Systems have been perfected to the point where about 99.5 percent of the original ash content of the coal can be removed, but extraction costs increase rapidly above the 95 percent recovery level. Modern power plants are normally equipped with control devices to provide a substantial degree of control. Under most future conditions it will probably be necessary to remove a high percent of the total ash, and removal of as much as 99.5 percent may be necessary in some circumstances.

The sulfur-derivative gases are generally considered to be the most troublesome pollutants associated with fossil-fuel furnaces. Sulfur is present in almost all fossil fuels. It is contained in coal as organic sulfur, sulphate, and pyrite. The pyrites are often removed by crushing the coal and separating the pyrite particles from the lighter coal by wet or dry flotation, thus eliminating a substantial part of the sulfur that occurs in pyrite form. The sulphates can be removed by chemical processes, but known methods are very expensive. No satisfactory method has been devised for extracting the organic sulfur.

Most of the sulfur that is contained in fuels that enter the furnace appears in the stack gases as sulfur dioxide (SO_2), in a concentration that is a function of the sulfur content of the fuel and the amount of excess air in the stack emission. A small fraction (2–3 percent) of the total sulfur in the coal is converted to sulfur trioxide (SO_3) in the combustion and heat transfer processes. After emission from the stack further oxidation of SO_2 to SO_3 and thence to sulfuric acid (H_2SO_4) may occur, depending upon meteorological conditions. Sulfuric acid particles in the air create a potential health hazard and are a nuisance and economic problem. Considerable research is needed to determine tolerable concentrations.

Some vegetation is less tolerant of SO_2 than are humans and animals, and concentrations as low as 0.5 ppm for 3 to 5 hours are known to have caused perceptable damage to sensitive species. The tolerance of a given species varies with environmental circumstances. Atmospheric sulfur dioxide is absorbed by plant foliage principally though minute pores, or stomata, in the under side of the leaf. The stomata open and close as environmental conditions change. When closed, plants can stand much higher concentrations of sulfur dioxide than when the stomata are open. The primary influences affecting the turgidity of the stomata are time of day, relative humidity, temperature, light, and moisture content of the soil. In general, conditions conducive to good growth are the ones rendering plants most susceptible to injury, but there is no constant relation between pollutant concentrations and degree of plant damage.

Removal of sulfur oxides from combustion gases by known methods is difficult and expensive. The three principal methods that have been tried, generally on an experimental or research basis, are washing, absorption, and oxidation. Washing with water or other chemical solutions has the disadvantage of cooling the stack gases and thus reducing their buoyancy and, consequently, their dispersion in the atmosphere. Experimental work currently underway on the use of absorbent pellets of carbon, alkalized alumina, or other materials that can be dropped through the ascending gases and then regenerated and recirculated offers some promise. Oxidation of sulfur dioxide with vanadium or other catalyst, and the recovery of a fairly concentrated sulfuric acid may prove practicable.

Nitric oxide (NO) and nitrogen dioxide (NO_2) are formed from air in the high temperatures of the combustion chamber. Rapid extraction of heat from the combustion gases tends to quench chemical reactions and thus prevent the reversion of these oxides to the nitrogen and oxygen of the air from which they are derived. These quenching effects are more pronounced in large furnaces operating at high temperatures. The oxides of nitrogen are in themselves irritating, and they may contribute to the photochemical reactions associated with power plant stack effluents. Dilute mixtures of hydrocarbons, nitrogen oxides, and sulfur dioxide experimentally exposed to sunlight produce toxic and vegetation-damaging substances, of which ozone and a newly identified series of compounds, the peroxacyl nitrates, are the most important. These reactions probably occur in power plant stack plumes. Research is needed to determine their extent and significance.

For each type of plant and animal life, there is a threshold concentration for each toxic substance above which adverse physiological effects may be expected. Threshold concentration levels have been established for relatively few species of plant and animal life. Much additional research is needed before accurate predictions can be made of damage potentials under any given set of circumstances. Until such studies are made, prudence demands a conservative approach that will limit damages, even though the degree of control is more stringent than may ultimately be found to be necessary.

Areas Affected by Emissions from a Power Plant

The assimilating capacity of the atmosphere is so great that air pollution from combustion processes would not be a problem in the foreseeable future if the contributed pollutants could be evenly distributed throughout the air mass as rapidly as they are produced. But geographic conditions and meteorologic phenomena do not always permit rapid dispersion of air pollutants, so harmful concentrations occur at some places and at some times. Weather is the variable that most often determines whether the pollutant accumulations will be consequential.

Air is most dense at the earth's surface, and normally air temperature decreases with altitude. As parcels of air are heated, however, their density is decreased and they are displaced by surrounding cooler air. Thus, heated gases emitted from a furnace stack tend to rise vertically until they are cooled to the point where their density equals that of the surrounding air. The height of rise above

A CATALYTIC OXIDATION PROCESS FOR REMOVING SULPHUR DIOXIDE FROM FLUE GAS

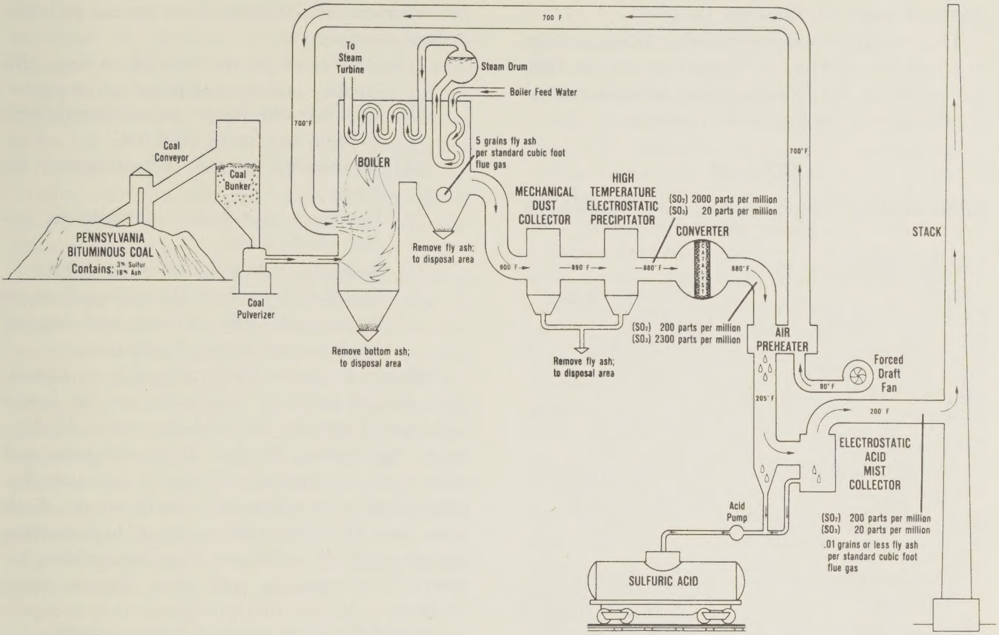

700 F
To Steam Turbine
Steam Drum
Boiler Feed Water
700°F
BOILER
5 grains fly ash per standard cubic foot flue gas
Coal Conveyor
Coal Bunker
PENNSYLVANIA BITUMINOUS COAL
Contains: 3% Sulfur 18% Ash
Coal Pulverizer
Remove bottom ash; to disposal area
Remove fly ash; to disposal area
MECHANICAL DUST COLLECTOR
HIGH TEMPERATURE ELECTROSTATIC PRECIPITATOR
(SO_2) 2000 parts per million
(SO_3) 20 parts per million
CONVERTER
CATALYST
900 F
890 F
880° F
880° F
Remove fly ash; to disposal area
(SO_2) 200 parts per million
(SO_3) 2300 parts per million
700° F
AIR PREHEATER
Forced Draft Fan
80° F
205° F
200° F
STACK
ELECTROSTATIC ACID MIST COLLECTOR
Acid Pump
(SO_2) 200 parts per million
(SO_3) 20 parts per million
.01 grains or less fly ash per standard cubic foot flue gas
SULFURIC ACID

FIGURE 82 *A schematic flow diagram of a sulphur-smoke removal system, using the catalytic oxidation process, installed in a pilot plant operation at the Seward Steam-Electric Station of Pennsylvania Electric Company.*

the stack depends upon wind and temperature conditions, rate of total heat discharge from the stack, and stack exit velocity. This combination of circumstances results in an effective stack height that is generally considerably greater than the physical height—an important factor in the ultimate distribution of the particulates and gases emitted. The effective height may range from practically no more than the physical height to several times the physical height.

The difference in temperature of the warmer air near the ground and the cooler air at higher elevations is usually greatest when a cool weather front moves into an area. The warm ground heats the air near it, but as this warm air rises it tends to be displaced by the cold air moving in, thus inducing rapid air rise and turbulence, both of which are beneficial to the dispersion processes. Conversely, warm fronts often create temperature inversions, with a layer of warm air superimposed above the cold air near the ground. In this situation, the warm air acts as a lid, limiting the upward currents normally present. Most severe air pollution incidents have been associated with prolonged periods of temperature inversion, coupled with fog and a condition of little or no wind movement.

The horizontal movement of air masses also is an important factor in air pollution. Wind tends to bend stack plumes to a horizontal position, and thus reduce the effective stack height. On the other hand, wind helps to move the stack gases away from the stack and to dilute them more rapidly. The relationship between dispersion and wind velocity depends primarily upon stack height. For power plants with low to moderately high stacks (200–400 feet), maximum ground concentrations occur under high wind conditions and within 1 to 3 miles of the plant. For plants with high stacks, maximum concentrations tend to occur under low wind conditions and at much greater distances, in a known instance 20 miles from the plant.

The magnitude of the potential pollution problem at plants expected to be in operation prior to 1980 is indicated by the following table, which is related to sulfur dioxide for illustrative purposes.

TABLE 43

Sulfur Dioxide Production in a Large Coal-Fired Power Plant

Installed capacity of power plant	4,000 megawatts
Coal heat content	12,000 Btu/lb.
Plant heat rate	8,500 Btu/kwh
Plant factor—6,000 hrs./yr.	68 percent
Assumed sulfur content of coal	1.6 percent [1]
Coal consumed:	
Average on annual basis	23,500 tons/day
Full load	34,500 tons/day
Sulfur dioxide content of stack gasses:	
Average on annual basis	600 tons/day (app.)
Full load	1,000 tons/day (app.)

[1] 1.6 pounds of raw sulfur per 100 pounds of coal. Sulfur content of coals used commercially in the United States ranges from 0.3 to 4.8 percent.

As indicated, normal operations of a typical power plant of this size under the assumed conditions could result in emission to the atmosphere of 600–1,000 tons of SO_2 per day. The emissions could be much smaller or double or even triple these amounts depending on the sulfur content of the coal. The potential for emissions of this magnitude would require most careful consideration of air pollution control requirements in site selection, design, and operational planning.

Methods of Avoiding or Controlling Pollution

Equipment now available can provide practically any necessary degree of control of fly ash emissions and, for plants of the size now in use, stacks can be provided to disperse gaseous emissions sufficiently to prevent any known health problems or appreciable botanical injury under most weather conditions. As power plants become larger, a higher degree of control of emissions may be necessary.

Careful site selection can be a major factor in avoiding air pollution problems. The major considerations in site selection from an air pollution control standpoint are:

(a) Conditions in the contiguous area, including natural terrain and structures.
(b) Existing and future population density.
(c) Existing and future land use.
(d) Meteorological and climatological regimes.
(e) Possible encroachment of stacks on airplane flight paths.
(f) Available fuels and their composition.
(g) Probable frequency of combined events that would cause seriously high ground level concentrations of pollutants.

Probably the most significant of these factors, from the air pollution standpoint, are the extent and type of existing and probable future developments surrounding the site. In heavily populated areas there is a limited tolerance to pollutants because of nuisance and health considerations. Such areas have the added disadvantage of high ambient concentration of pollutants from automobiles, industrial developments, and other sources, upon which the pollution from stack gases would be superimposed. In rural areas, the more troublesome public health considerations are less severe and vegetation may be the more critical element. Grains, legumes, and some ornamental plants are more sensitive to air pollution injury than most forest species, and damage to the smaller plants is usually of more consequence economically.

Terrain and the height of developments around a site are extremely important. Obviously, a hill or a skyscraper that is higher than an adjacent smoke stack is more vulnerable to pollution damage than the areas at the level of the stack base. Perhaps more important is the trapping of pollution in enclosed valleys during temperature inversions. The area of gaseous dispersion in valleys is also affected by the tendency of air to move either up or down the valley, thus limiting the wind direction variable. Some of these situations may be improved by constructing stacks with greater height than the surrounding hills.

Meteorological records are important in predicting the frequency of occurrence of problem conditions in areas being considered. The frequency, intensity, and duration of temperature inversions and the frequency and duration of extremely low or high winds provide indications that are helpful in appraising air pollution risks. The Public Health Service, in cooperation with the Weather Bureau, maintains a network of observation stations throughout the United States to identify areas where temperature inversions or potential air pollution problems may develop. Data being collected at the 225 network stations now in the system, and at other private or public stations throughout the country, provide a reasonably accurate indication of the problems that can be anticipated for any particular area.

Even at relatively favorable sites, plant operating procedures will need to include measures for air pollution control. Careful monitoring of weather conditions and pollution levels will be an essential operating procedure for the large plants of the future, as it often is now. With such monitoring, emergency control measures can be instituted when impending pollution conditions warrant. Such measures may include shifting to the use of gas or low-sulfur coal, or controlling the generation at plants on an interconnected system so as to minimize the generation at those plants where atmospheric conditions are most adverse.

Administrative Aspects of Air Pollution Control

While research is being conducted on the technical problems of air pollution control, preventive or corrective measures of the type discussed above are available to meet many of the immediately foreseeable requirements. The ability to do the job does not, however, insure that it will be done. Federal, State, and local governments have therefore taken an interest in air pollution control, particularly in recent years, and attempts are being made to provide legal controls that will protect the general public without unduly restricting the use of the equipment or facilities that cause pollution. A national air pollution control policy has been enunciated in Public Law 84–159 (60 Stat. 360) enacted July 14, 1955; in the "Clean Air Act," Public Law 88–206, of December 17, 1963; and elsewhere. That policy establishes that the primary responsibility for air pollution control lies with the states and local agencies, but that assistance in research, administration, and other aspects of control programs will be provided by the Federal government. Thirty-two states have some type of air pollution control legislation, and many local areas have adopted ordinances dealing with their particular problems.

The Los Angeles metropolitan area has been plagued by an air pollution problem for years. Air pollution in Los Angeles is the result of contaminants produced by all sectors of its industrial and human endeavors. In addition to some 17,000 productive industries in the metropolitan area, 3 million automobiles burning 5½ million gallons of gasoline per day contribute contaminants to the air. Smog is a frequent threat, even with the controls that have been instituted. Without such controls, the situation would often be intolerable.

While the Los Angeles problems are in some respects unique, the control procedures that have been adopted there are indicative of what may be required in other problem areas. Basic to the Los Angeles control system is a program of monitoring both weather conditions and levels of air contaminants. Three stages of alert related to the severity of exposure have been adopted, and appropriate control measures are instituted whenever necessary. The limits of contamination for each of the three stages are summarized in table 44 which also shows the highest concentrations that have been recorded and the dates they occurred. In the first-stage alert, all unnecessary activity which might pollute the air must be avoided. A second-stage alert indicates a health menace, and the County Air Pollution Control Director may impose limitations on the general operation of vehicles and may restrict the operations of public utilities and other industries to those essential to continued operation of the industrial complex. The third-stage alert is evidence of a dangerous health menace, and appropriate measures may be taken under the California Disaster Act to limit activities to emergency needs and such other operations as are considered tolerable.

Los Angeles experienced 40 first-stage alerts during the 1955–60 period, ranging from 25 minutes to 3½ hours in duration. All but one of these were caused by ozone (O_3) concentrations of over 0.5 parts per million. To reach this concentration directly would require dispersal of 1,000 tons of O_3 in the Los Angeles basin. However, no industry releases significant amounts of ozone. The concentrations appear to be the result of the photochemical reaction of nitrogen dioxide and hydrocarbons.

TABLE 44

Air Pollution Alert Levels in Los Angeles County

Contaminant	Stages of alert (Contaminant concentration in p.p.m.[2]) 1st	2nd	3rd	High reading in county p.p.m.[2]	Date
Ozone	0.5	1.0	1.5	0.90	9/13/55
Nitrogen oxide	3	5	10	3.13	12/19/60
Carbon monoxide	100	200	300	72	11/24/59
Sulfur oxides [1]	3	5	10	2.49	6/27/57

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[1] Ambient air quality standards adopted by the California Department of Public Health, December 4, 1959, classify an SO_2 level of 1 ppm for 1 hour or 0.3 ppm for 8 hours as "adverse" levels, i.e., levels at which there will be sensory irritation, damage to vegetation, reduction in visibility, or similar effects.

[2] Parts per million.

The State of California is taking measures to reduce contaminant emission from automobiles by requiring installation of devices to improve combustion. Research into and development of afterburners in auto exhaust lines is also underway. Recently, Los Angeles required all of its industries to burn gas, or fuel oil containing less than 0.5 percent of sulfur by weight, as the regular fuels. Oil with more than 0.5 percent sulfur, which is the kind generally available at normal prices, may be used only when gas is not available.

Many other metropolitan areas are planning to expand their pollution control regulations, by building upon the knowledge gained from past educational and control efforts. New regulations being considered by the New York City Department of Air Polluton Control include specifications on fuel standards, including restrictions on sulfur content, as well as limitations on the concentrations of pollutants that may be emitted from furnace stacks.

Conclusive information is generally not available to identify the maximum concentrations of pollutants that are tolerable at the recipient level, especially in regard to health, and there is no conclusive way to relate environmental circumstances to permissible emission levels. This leads to the hazard that well meant legislative or regulatory controls may prove to be technically unreasonable or economically unrealistic. Until better background information is available, it appears that the most prudent control specifications would be those based on the "reasonableness" concept, leaving to the pollution control regulatory body the decision as to what is reasonable in instances where self-regulation by industry does not adequately protect the public interest.

Summary and Conclusions

1. Thermal pollution of water, and general pollution of air will become increasingly severe problems in the United States as fossil and nuclear fueled energy-conversions are stepped up to meet the future demands of an enlarged population with a higher standard of living. Additional emphasis on pollution control, from the standpoints of both industry and government, is essential.

2. Fossil-fueled power plants are significant, but not dominant potential sources of thermal and air pollution. However, unless the large power plants envisioned for the future are thoughtfully planned with respect to environmental effects they could create severe local pollution problems.

3. Present technology makes possible control of water and air pollution at existing and additional power plants to acceptable levels. However, costs of highly effective controls by currently known methods and equipment could add significantly to future costs for power generation. More information is needed on methods and equipment for control of emissions to assure reasonable future abatement at reasonable cost.

4. More research is needed to identify damage limits of both air pollution and thermal pollution of water.

5. Careful plant site selection can minimize the adverse economic and social effects of pollution. Flexible operating procedures with adjustments to meet unusual pollution hazards may permit economies without sacrificing safety.

6. Considering these and other factors, the anticipated reductions in the cost of electrical energy may be decreased as a result of the need for more stringent water and air pollution controls, but the nation's capacity to produce needed electrical energy will not be impaired because of these environmental considerations.

CHAPTER 10

TRANSMISSION OF ELECTRIC POWER

An efficient, low-cost power supply network for the United States must include a reliable, economical means for transporting large blocks of power, sometimes for long distances. The many benefits discussed throughout this report from larger generating units, coordinated pooling with savings of reserve capacity, exchange of power to take advantage of diversity, economic interchange between systems and areas, selection of most favorable generating sites and types of power supply—all are dependent upon high-voltage, long-distance electrical transmission. In this context, the historical function of electric transmission circuits has assumed new dimensions.

Originally, long lines of high voltage were principally associated with the transfer of energy from remote hydroelectric developments to industrial and population centers. As early as 1913, the Big Creek line in southern California was built over a distance of 240 miles into Los Angeles, and operated at 150 kilovolts. In 1923, the voltage on this line was raised to 220 kilovolts. Later the city of Los Angeles installed 287-kilovolt lines to bring power into that city from Hoover Dam, some 300 miles away.

But high voltage transmission is also extensively employed for the interconnection of transmission networks; and as loads have increased, transmission voltages have been raised to deliver large amounts of power even for relatively short distances. Today's emphasis on coordination between systems is the culmination of a trend which began in the late 1920's, when pioneering systems realized that distinct economies and improved reliability of service could be achieved through strong interties. Interconnection contracts were entered into and, in some instances, utilities began to join into "pools," some restricted in area and functions, and others broad or even regionwide.

With pool operation, technical problems arose which required refinements of equipment, standardization of operating practices, acceptance of the principle of free flow of electric power throughout the networks, and formulation of new types of contractual arrangements between the parties, in order to enable the parties to operate their combined systems more or less as a unit.

The History of the Development of EHV

Prior to World War II there seemed to be little incentive in this country for intensive efforts to develop voltages higher than 230 kilovolts, which in itself, was not widely used outside of the Pacific coast, a predominantly hydroelectric area. Extensive networks of 115 kilovolts, 138 kilovolts and 161 kilovolts apparently met the needs of the pattern of power supply which predominated throughout the country in which generating stations were usually located close to load centers, thus requiring relatively short transmission distances.

Aside from the 287-kilovolt line from Hoover Dam to Los Angeles, previously mentioned, there were no EHV[1] lines in existence in this country prior to the early 1950's. This long lag in EHV development came to a halt in the postwar period with the construction of extensive 345-kilovolt systems.

Following World War II, the need for transmission lines in the extra-high-voltage range became imperative. The earliest 345-kilovolt transmission in the United States was introduced in the early 1950's on the American Electric Power System in the West Virginia-Ohio area, and lines of the same voltage soon followed on the Bonneville Power System in Oregon and Washington. In the past 10 years an impressive amount of 345 kilovolts has been placed in service, and today over 4,000 circuit miles of 345 kilovolts are in operation and several hundred additional miles are under construction. Utilities in the United States operate more than 90,000 miles of transmission lines of 138 kilovolts to 345 kilovolts.

EHV lines at even higher levels have been in existence in other countries for several years serving the transmission of large blocks of power for long

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[1] The term extra-high-voltage (EHV) is commonly applied to transmission lines higher than 230 kilovolts.

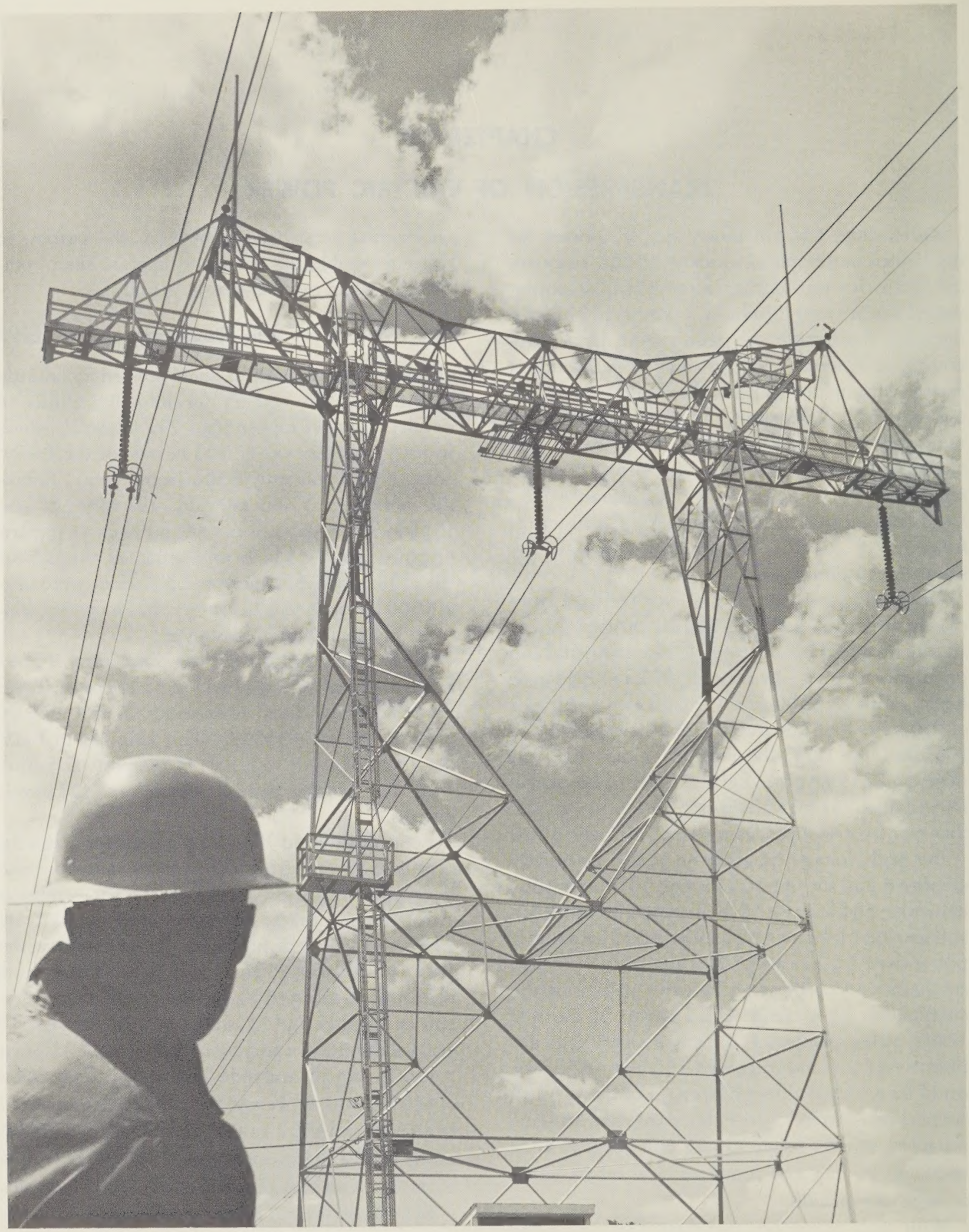


FIGURE 83 *This experimental aluminum tower designed for EHV transmission is part of continuing development to make feasible the economic transmission of large amounts of power over long distances. The tower is adaptable to various configurations of conductors and insulators for voltages up to 750 kilovolts.*

distances from hydroelectric developments. In Sweden, 400 kilovolts was placed in operation in 1952, and in Russia in 1954. The voltage on the Russian lines was increased to 500 kilovolts in 1961, and plans have been announced for energizing a 70-mile test line at 750 kilovolts this year. Construction has been initiated in Canada by the Quebec Hydro Electric Commission for a 370-mile line rated at 735 kilovolts.

The pace of EHV construction in this country is now rapid. In 1961, the Pennsylvania Electric Co. energized a 13-mile experimental line at 460 kilovolts for operating experience at this EHV level. In 1962, the Virginia Electric and Power Co. announced firm plans for transporting power from a mine-mouth steam-electric plant in West Virginia to their load centers near Washington, D.C., and Richmond, Va. This line is designed for 500 kilovolts and will be in service late in 1964. By the end of 1963 plans were announced for other 500-kilovolt projects in Pennsylvania, the Middle-South States, California, and in the Pacific-Northwest. While there are no transmission lines with voltages higher than 345 kilovolts in commercial operation in this country today, by 1967 more than 3,000 miles of 500-kilovolt lines are expected to be in service.

Transmission Technology

It has been a fairly normal practice to expand an existing network with new transmission lines of about twice the voltage of the existing network. For example, 345 kilovolts is an effective level for the expansion of 138 kilovolts and 161-kilovolt systems, and 500 kilovolts would be a logical next step for 230-kilovolt systems.

In 1947, full-scale testing of lines and terminal equipment was initiated to explore problems associated with EHV levels. Today, research is well underway for transmission up to 750 kilovolts and research at higher voltages will follow. The extensive operating experience soon to be gained will clarify questions regarding transient overvoltages, radio and television interference, and the performance of circuit breakers, lightning arresters, shunt and series capacitors and reactors, and other equipment.

The most important fact concerning EHV technology is that the higher voltages result in lower transmission costs. The costs of these high voltage lines and terminal equipment increase more or less in proportion to the voltage but the power capability increases basically as the square of the voltage. Losses in transmission are also reduced. As a result of these factors, the cost per unit of power transfer decreases with escalation of voltage levels. This fact explains why, despite the more than doubling of material and labor costs in the last 20 years, power is transmitted today at lower unit costs than in 1947.

While the capital investment for transmission lines will vary substantially from open plains country to congested metropolitan areas, the following table shows the relationships between line cost and load carrying capacity over a range of voltages:

TABLE 45

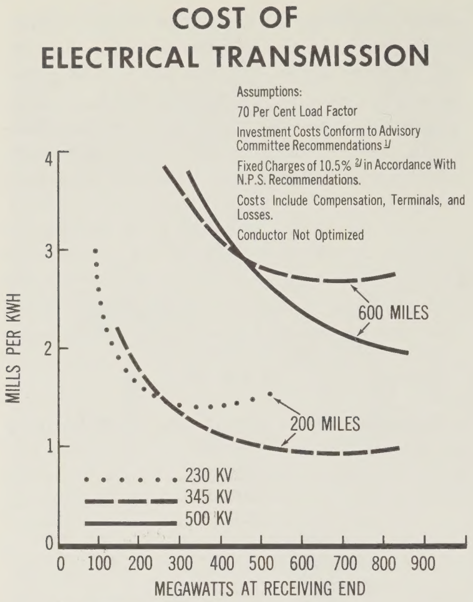
Relationship of Investment and Load Carrying Capacity

	Relative investment	Relative load capacity	Representative investment per mile, including right-of-way
230 kv...	1	1	$60, 000
345 kv...	1⅓	2¾	77, 000
500 kv...	1⅔	6	99, 000
700 kv...	2½	13½	143, 000

Source: Advisory Committee Reports Nos. 10 and 14, reproduced in Part II.

Figure 84 presents typical costs for transmitting power and cost and load carrying relationships between lines varying from 230 kilovolts to 500 kilovolts. The costs are based on a single circuit line. To assure firm power delivery two circuits would be required, possibly with sectionalizing stations, but the ratios would remain about the same. The delivery of 150 megawatts at 230 kilovolts for a distance of 200 miles will have a transmission cost about equal to the delivery of 800 megawatts at 500 kilovolts for a distance of 600 miles.

The curves illustrate that for a given distance and voltage there is a level of load which results in a minimum cost per kilowatt-hour transmitted. These curves form overlapping loops which are shifted to the right for higher voltages. Each increase in voltage level results in a lower minimum cost per unit. They illustrate the economic advantage of using progressively higher voltage as the



1/ Advisory Committee Report No. 10

2/ Advisory Committee Report No. 17

FIGURE 84

load increases; this is true for either distance shown—200 or 600 miles.

Line Compensation

Many innovations in line design have occurred during the past 15 years. Rather than merely extrapolating and enlarging, engineers have introduced new design concepts and materials. The power-carrying ability of an alternating current line and the distance over which the power can be transmitted are limited by the lines inductive reactance. This is an electrical phenomenon which impedes the flow of current and may be lessened or neutralized by a compensating device known as a series capacitor. The degree of compensation is expressed as a percentage.

Another compensating device employed on AC transmission lines is the shunt reactor. Shunt reactors are a device which compensate for the shunt capacitance between parallel conductors of an AC transmission line, which if uncompensated, produces a charging current in the line and increases line voltage. They serve to maintain the desired voltage when the line is open or lightly loaded.[2]

At a relatively low cost per kilowatt of capacity gained, series capacitors may be installed which can more than double the load carrying capability under optimum circumstances. In cases where lines are built in anticipation of a future increase in loading, such capacitors can be deferred until system growth justifies the additional carrying capacity.

Many studies of long-distance transmission have demonstrated that the most economic loading is obtained with a substantial amount of compensation (50 percent or more). For lines several hundred miles long, the cost of compensation at the economic loading may approach one-fourth of the total transmission investment for the lines and terminals.

Conductors

For high-voltage lines the conductor material is almost universally aluminum, either pure aluminum which has the best conductivity, or aluminum alloy which is stronger but has less current-carrying capability. To avoid electrical breakdown of the air at the surface of the conductor, the diameter must be increased approximately in proportion to the voltage. This results in 345-kilovolt conductors over 1½ inches in diameter and 500-kilovolt conductors 2½ inches in diameter. The latter size weighs nearly 4 pounds per foot and presents difficulties in manufacture, shipping, and installation.

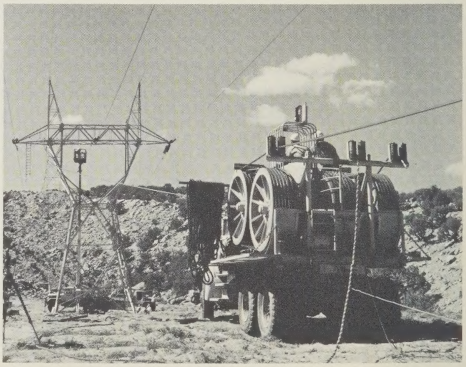


FIGURE 85 *Control tensioning is applied with equipment, at right, to reach conductor at tower in background. "High reach" crane at tower is being used for attaching insulator assemblies.*

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[2] Advisory Committee Report No. 14, p. 146 of Part II.

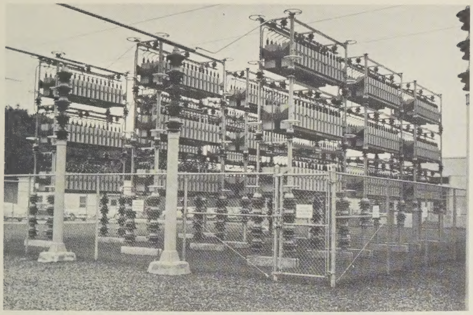

FIGURE 86 *This 230 kilovolt shunt capacitor installation at the Covington Substation of the Bonneville Power Administration system improves line voltage by correcting power factor.*

Fortunately, a scheme known as "bundling" alleviates these difficulties and provides other benefits. It consists of mounting two or more cables of much smaller diameter spaced several inches apart. The electrical stress on the air is reduced to the equivalent of a large diameter single conductor. Line impedance is decreased and the electrical load capability is increased by 25 percent or more. Also, the radio interference characteristics are improved as compared with an equivalent single conductor. Practically all extra-high-voltage lines today are built with bundle conductors. The preferred construction recommended by the Advisory Committee [3] includes bundle conductors for all AC lines above 230 kilovolts.

Aluminum is the preferred material for transmission line conductors today, although it has only 60 percent of the current-carrying capacity of copper. The fact that the copper metal is more expensive than aluminum is not the only disadvantage. Copper, having better current-carrying capability, consequently has smaller diameter than aluminum for the same current rating. This smaller diameter is not adequate for high voltages, and a more costly design of conductor is required to expand the diameter. In contrast, the poorer current-carrying characteristic of the aluminum works to its advantage as it will have inherently a larger diameter which is suitable for the high voltage without the necessity of expansion.

Insulation

For overhead transmission lines the conductors are always bare metal. Rather than supporting these wires on insulating devices, they are suspended below the crossarms by means of a flexible "string" of porcelain or glass discs. For higher voltages it is merely necessary to add more units to the string. The strength rating of insulator discs most commonly used was formerly 15,000 pounds. With the larger conductors it became necessary to use two, three, or more strings in parallel. Today, insulators rated at 25,000, 36,000, and up to 60,000 pounds are available commercially. These are adequate for the voltages envisioned between now and 1980.

A type of design being widely adopted is "V" string support, using two insulator strings at an angle of nearly 90 degrees. While this requires additional insulators, the conductor is restrained from swinging in a crosswind, resulting in a reduction in

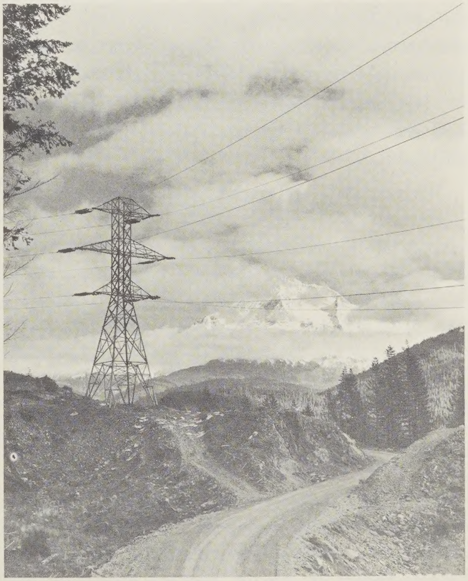

FIGURE 87 *This double circuit 287 kilovolt transmission line, in the vicinity of majestic Mt. Hood, was constructed by the Bonneville Power Administration in 1953 to bring power from Columbia River plants to the Portland load area.*

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[3] Advisory Committee Report No. 10, p. 87 of Part II.

the required size of the tower structures and the width of right-of-way. These reductions may result in savings that more than offset the additional insulation cost.

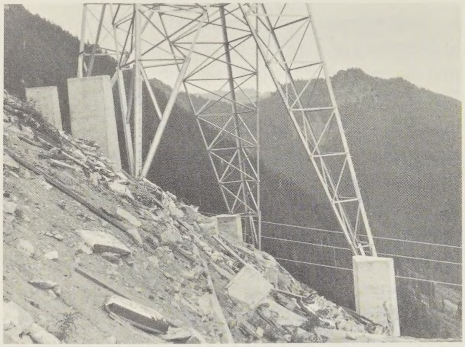

FIGURE 88 *Rugged concrete guards protect tower legs from snow slides in Snoqualmie Pass, Washington on 345 kilovolt transmission line of the Bonneville Power Administration.*

A different form of suspension using long procelain rods has been used in other countries but has not been adapted to U.S. designs except on an experimental basis. Recently, a new plastic insulator has been introduced by an American manufacturer and is undergoing extensive service testing on operating lines.

It is not likely that major reductions in insulation costs will occur before 1980. At each voltage level a minimum clearance from the steel structure is required to prevent flashover, particularly under wet conditions. However, as more knowledge is gained with respect to transient system overvoltages and gradual improvements in equipment for control, less air gap clearance will be possible. For example, present 345-kilovolt designs have less insulation than some of the earliest 230 kilovolt lines. The 287-kilovolt line which was built from Hoover Dam to Los Angeles in 1936 has an insulation level which would be adequate for some 500-kilovolt systems, particularly in view of the improvements in circuit breaker operation and lightning arrester characteristics. Transmission line insulation may be one of the critical factors on lines above 750 kilovolts and research should move forward in this area.

Towers

Just as there are dozens of ways to construct a highway bridge, there are also dozens of ways to design the supporting structures for overhead conductors. (See fig. 90.) Differences in climate are responsible for some of the design variations. In Florida, lines must resist hurricanes, while in the north they must be capable of withstanding ice storms. The severity of lightning differs widely. The topography of the land which a line traverses may vary from open flat plateau to wooded mountain. Construction requirements and maintenance, particularly where access is difficult or where corrosion is a problem, are important factors in the selection of tower material and design. Tower weights have been reduced in recent years following changes in longitudinal loading assumptions. particularly when bundled conductors are used. Today, most tower designs are optimized in dimensions and weights through extensive analyses using computers. Helicopters are gradually being used more frequently for erection of towers and string-

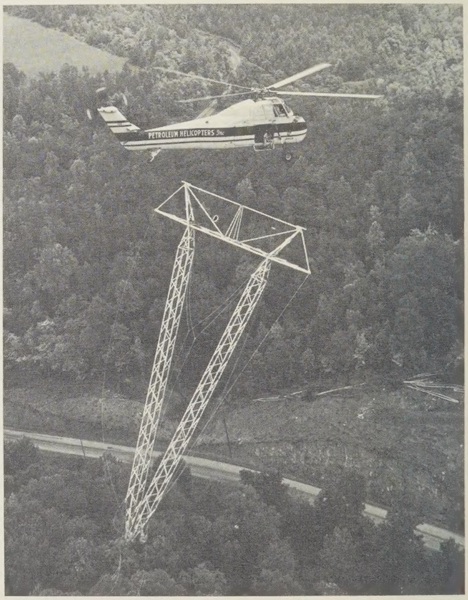

FIGURE 89 *Lightweight towers, together with new structural designs and new installation techniques, are cutting the cost of transmission line construction in rugged terrain.*

ing of conductors in difficult terrain. This method of erection favors towers of light weight and will probably lead to more extensive use of aluminum.

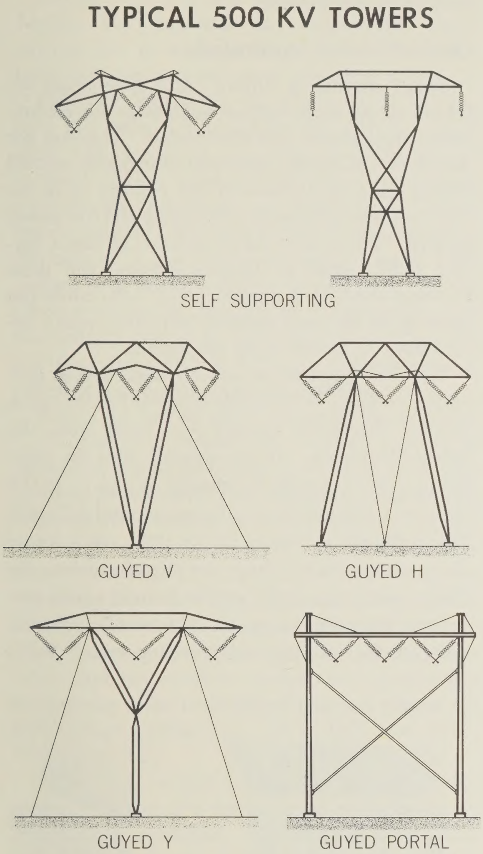

Figure 90

Because of growing awareness of aesthetic considerations, efforts are being made to improve the appearance of transmission facilities. For example, the 500 kilovolt towers of the Virginia Electric and Power Co. utilize a special steel alloy which is stronger, less bulky, and weathers naturally to a brownish color which will blend into the terrain.

Rights-of-Way

Electric utilities are facing mounting public opposition to the acquisition of right-of-way for lines of all voltages and for substation sites. The following excerpt from Advisory Committee Report No. 23 contains a discussion of the subject in relation to distribution facilities.

"For appearance reasons, utilities are being subjected to increasing pressures to place their facilities in uneconomical locations, to install them underground, or to use more costly types of aboveground construction. If they are to continue in the future to supply adequate and reliable service at low rates, solutions must be found to this problem. On the part of the utilities, this requires that they continue their efforts to develop lower cost underground and aesthetically pleasing aboveground designs for their facilities, and that they make every reasonable effort to harmonize the appearance of their facilities with the neighborhoods in which they are installed. On the part of the public authorities, it requires that they recognize the public interest in the economical distribution of electricity and resist the pressures from minority groups and special interests to force utilities to use uneconomical locations and forms of construction." [4]

As a result of this situation, present facilities are being used more intensively in lieu of the acquisition of new rights-of-way. This is accomplished by increasing the capability of existing facilities, rebuilding lines to operate at higher voltages, and substituting multiple circuit structures for single circuits.

Terminal Equipment

The development of transformers, breakers, and protective equipment has kept abreast of EHV progress. The same factors which have permitted lower insulation for the transmission structures have likewise allowed equipment designers to reduce the size of insulation in the terminal equipment. Present circuit breakers are rated for two-cycle interrupting time, whereas 30 years ago breakers required 12 to 15 cycles to interrupt a fault.[5] A companion development is "high speed reclosing." When lightning flashes over a string of insulators, establishing an arc path to ground, the breaker must interrupt the power arc which follows, after which it can reclose and re-establish the service provided the interconnected systems have not drifted too far apart in electrical phase relation. Today, in more than 9 out of 10 such cases, the line is successfully restored within a third of a second without noticeable disturbance to the system.

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[4] Advisory Committee Report No. 23, p. 391 of Part II.

[5] Engineers measure such operations in terms of the number of cycles of the alternating voltage. For example, in the United States, with 60 cycles per second, 12-cycle interrupting time would be equivalent to one-fifth of a second; two cycles would be one-thirtieth of a second. Considering the physical size of the interrupting breakers, particularly for EHV, this represents a severe mechanical problem to precisely control the opening and closing operations irrespective of the electrical difficulties.

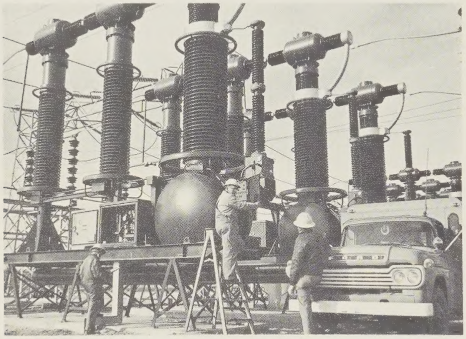

FIGURE 91 *This 345 kilovolt two-cycle air blast circuit breaker installed at a substation on the American Electric Power System typifies the giant size of ancillary equipment used with EHV transmission.*

Insulated Cables

Efforts are frequently made to require utilities to place transmission circuits underground. In some circumstances buried cables are advantageous, but the usual cost is 5 to 10 times that of overhead circuits. Likewise, there are technical limitations on the use of high-voltage underground cables. The 230-kilovolt cable has been introduced in the United States within the last decade, 345 kilovolt cable is being installed today in New York City, but 500-kilovolt cable is only under development, and it is uncertain as to whether present technologies are adequate for insulation at such a high voltage.

The growing demand for underground delivery of power into cities from outlying generating plants where special treatment is required to preserve scenic values portends a much larger application of cables in power transmission. Extensive additional research is necessary to improve the insulating material. It has been suggested that with present laboratory techniques for designing and creating molecules with selected characteristics, a more favorable synthetic insulating material can be devised. To date, however, only limited research has been devoted to this problem.

Direct-Current Transmission

Today alternating current (AC) is generally accepted as the most suitable technology for electric power transmission and distribution. This was not always so. A healthy, technical controversy, ensued during the early decades of the industry as to the most efficient method of developing electric power systems. There were the proponents of direct current (DC)—such as Thomas Edison—and those favoring alternating current (AC), who could not agree as to the most suitable frequency, which varied from 25 to 133 cycles per second.

The first transmission was accomplished at generator voltage. With the development of the transformer, alternating current was freed from this voltage limitation. It was possible with the alternating current systems to advance as high as 30,000 volts on a 100-mile line in Germany, and a 75-mile line in the United States before 1900. As a means of providing high voltage for direct current, the Thury system was developed in France, which consisted of cascading many direct-current machines in series at the sending and receiving ends. For a

DIRECT CURRENT VALVE WITH FOUR ANODES

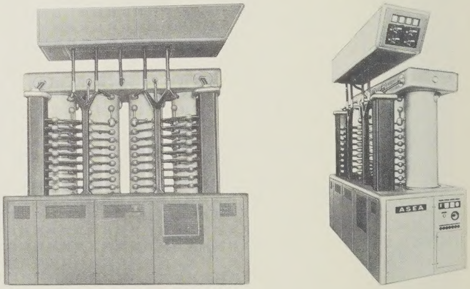

FIGURE 92 *The four-anode valve is one physical arrangement of a high voltage, large capacity facility used to connect alternating current and direct current circuits for the transfer of electric energy between their systems. Through the process of rectification in the converter, alternating-current power is changed to direct-current power or direct-current power is changed to alternating current power.*

112-mile line from Moutiers to Lyon constructed in 1905, several generators were placed in series to provide 57,000 volts direct current. Interestingly, this line continued in service until 1937.

During the latter half of the 30's, the General Electric Co. operated an experimental direct current line in western Massachusetts at 27,000 volts, utilizing mercury-vapor converter tubes.

Following World War II, practically all DC systems had been supplanted by AC, although engineers still recognized the inherent simplicity and economy of DC. This was particularly true where long-distance submarine or underground cables were involved. Alternating current is more versatile because it can readily be stepped up to high voltage with simple, efficient transformers. Direct current cannot be handled by transformers, and high voltage devices for converting from AC to DC and back from DC to AC were not available in power ratings necessary for transmission.

Within the last decade, a successful development in Sweden of a mercury arc "valve" capable of voltages in the order of 100 kilovolts or more, and currents in the order of a thousand amperes has renewed the interest in direct-current as a supplement to alternating-current systems. The first full-scale commercial DC transmission installation was completed between the Swedish mainland and the Island of Gotland (a distance of 60 miles) in 1954. This consisted of a single 100-kilovolt submarine cable, and the excellent performance record has demonstrated the feasibility of the new valves for high-voltage rectification (AC to DC) and inversion (DC to AC).

In 1961, a second underwater direct current project was placed in service between England and France. Experimental overhead DC lines have been built in Russia with the objective of transmitting hydro power long distances. Today, many more projects are under construction and others are receiving serious consideration in several countries of the world, although no project has reached the construction stage in the United States. Table 46 illustrates that over 2 million kilowatts will be carried on DC transmission facilities by 1965.

The transfer of power over DC transmission lines depends on the voltage drop between the two terminals. With AC the power transfer depends upon the angular phase difference between the sending and receiving voltages. There is no transfer of synchronizing or reactive power in DC. The operation of a DC circuit which interconnects two separate AC networks is practically independent of the variables in the power characteristics of the two networks. In some circumstances this characteristic is a distinct advantage. For example, the installation in Japan connects two systems of different frequencies. Similarly, the DC links across the English Channel and from the Scandinavian Peninsula to Europe simplify the interconnections of large, independent networks.

Insulation requirements for a nominal voltage are less with DC than with AC and only two conductors are required per DC circuit as compared with three for AC. The consequent saving in materials accounts for the fact that the cost of a DC line is about two-thirds of that for an AC line with comparable capacity. The terminal facilities, however, for converting between AC and DC are a major item of cost. While high-voltage AC transmission requires transformation equipment at each terminal, DC requires similar transformation plus a reactive supply, converters, and related controls. The savings in DC line cost and lower transmission losses must offset the additional cost of the terminals to make DC transmission as economical as AC. As a consequence, it will be noted in table 46 that several hundred miles of transmission lines are involved in each of the overland DC projects, pointing up the fact that DC is more likely to have the economic advantage as the length of the uninterrupted transmission line increases.

An insulated cable has the characteristic of storing electrical energy. The current which flows into the cable as the voltage rises is called the "charging" current. The magnitude of the charge is very nearly proportional to the length of the cable. With alternating-current circuits this charging current flows into and out of the cable as the voltage reverses. With AC, therefore, the full current-carrying capacity of the cable may be required merely to charge the insulation. This imposes a limitation on the permissible length of the underground and underwater circuits when alternating current is employed. In contrast, a direct-current circuit maintains essentially constant voltage so that no similar distance limitation applies. In addition, the insulation can be subjected to much higher voltage when used for direct current. For these two reasons 2 to 10 times as much power can be carried on the same cable with DC instead of AC. Another factor favorable to underwater DC installations

TABLE 46

DC Transmission Lines In Service, Under Construction or Proposed

Country	Project	Voltage (kv)	Power transfer (mw)	Length (miles)	Status
Sweden*	Gotland	100	20	60	Operating since 1954.
England, France*	Cross-Channel	200	160	40	Energized December 1961; some operating problems.
Russia	Donbass-Volgograd.	800	750	300	Completed—to energize in 1964.
New Zealand*	North-South Islands.	500	600	385	Under construction—to energize in 1965.
Italy*	Sardinia	200	200	280	Under construction—to energize in 1965.
Sweden, Denmark.*	Konti-Scan	250	250	150	Under construction—to energize in 1965.
Japan	Honshu Intertie—50 to 60 cycles.	250	300	0	Under construction—to energize in 1965.
Totals by 1965			2, 280	1, 215	
United States	Pacific NW-SW	750	2, 600[1]	800[2]	2–DC lines included in approved intertie program.
United States	Canada-New York City.	900	2, 000	300	Proposed import of hydropower.
Russia	Various	1, 400	....	....	Proposed long distance ties.
United States	DC test line	1, 100	....	5	Energized 1964 for experimental investigations.
Grand totals			6, 880	3, 120	

*Projects in which submarine cables are involved.

[1] Transfer capability of two lines.

[2] Approximate length of each line.

which is utilized in the Gotland and Sardinia installations is that only a single insulated conductor is used and the seawater serves as a return path to complete the circuit.

As may be noted from the tabulation, many of the present direct-current projects involve submarine cable. With such installations leading the way in the development of DC technology, it is probable that many more applications of DC transmission gradually will be found economically favorable.

Some apprehension has been voiced with respect to possible corrosion of underground facilities due to earth currents resulting from direct-current transmission. The problem is being studied extensively as there are significant benefits to be gained from single pole systems such as in the Gotland and Sardinia installations. However, the proposals for transmission lines in the United States have been based on two-pole systems in which the ground current is not necessary and would occur only inadvertently during emergency conditions.

The report of the National Power Survey Advisory Committee[6] states:

"Investigations conducted in Sweden tend to confirm that ground return on DC systems is feasible provided the terminal station grounds are adequately designed and sufficiently remote from other facilities, such as pipelines which might suffer harmful effects. . . . These tests also led to the conclusion that if the station ground terminations are six to seven miles removed from the vicinity of pipelines, other cables, etc., no harmful effects will be incurred."

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[6] Advisory Committee Report No. 20, p. 296 of Part II.

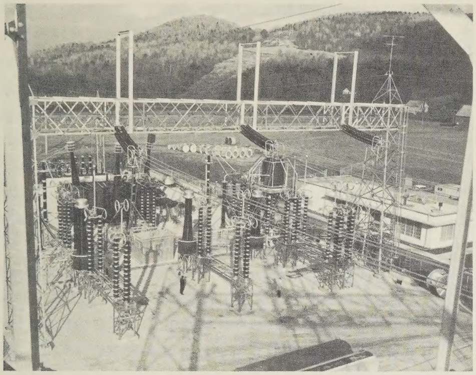

FIGURE 93 *The spacing of conductors on this transmission tower, one of several types erected at the General Electric Company's high voltage test facilities near Pittsfield, Mass., is adequate for a transmission voltage of 750 kilovolts.*

In summary, the present situations favorable to DC are generally those which involve (1) several hundred miles of overhead line without intermediate taps; (2) about 30 miles or more of underground or submarine cable; and (3) the transmission between two networks which have dissimilar frequencies or where frequency control and stability of the connected networks would be difficult.

Research and Development

Much of the recent research and development efforts relating to electric power transmission and distribution has been undertaken jointly by manufacturers and utilities. Cooperative projects between the utilities and the manufacturers have become essential in order to obtain realistic performance evaluation of newly developed equipment under operating conditions. The following are some examples, but this summary does not attempt to enumerate all such projects:

(a) TIDD, 1946. Sponsored by American Electric Power for investigating terminal equipment and line design up to 500 kv on test lines 1½ miles long.

(b) LEADVILLE, 1956. Sponsored by Public Service Co. of Colorado for continued investigation as related to transmission at high altitudes. Test line 1.3 miles at 10,000 feet.

(c) PROJECT EHV, 1960. Sponsored by General Electric Co. and consisting of a 4.3-mile experimental line at operating voltages up to 750 kv.

(d) PENELEC, 1960. Sponsored by the Pennsylvania Electric Co. and consisting of a 13-mile developmental line which was the first three-phase, 460-kv operating line in the United States.

(e) APPLE GROVE, 1961. Sponsored by AEP and Westinghouse Cos. to investigate line and terminal performance up to 750 kv.

(f) CORNELL, 1961. Sponsored by several insulated cable manufacturers to develop suitable cable for 345 kv transmission.

(g) BIG EDDY DC, 1963. Sponsored by the Bonneville Power Administration to investigate high-voltage, direct-current transmission.

(h) WANAPUM (proposed). Sponsored by Grant County PUD, in the State of Washington, as a high-energy-high-voltage test and research facility to be available to all utilities or manufacturers.

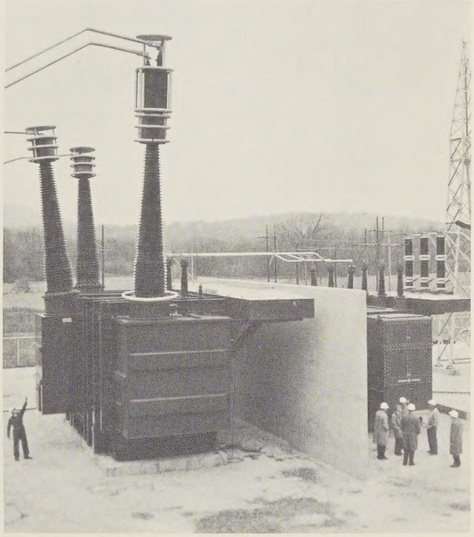

FIGURE 94 *Huge power transformer steps up incoming voltage to a range of 460 kilovolts to 750 kilovolts at General Electric's Project EHV near Pittsfield, Mass. Transformer, at right, regulates the 115,000 volt incoming supply by ±30 percent to provide range in test voltage. Transformer bushings extend 18 feet above and 10 feet into the transformer.*

In recognition of the need for a broad examination of the electric power industry's present research and development efforts, the Federal Power Commission in July 1963 sponsored the organization of an eleven member select committee to study the possible formation of an industry-wide organization to encourage and coordinate greater research and development activities in the electric power industry. It was suggested to the committee that they should feel free to investigate all aspects of the need for a permanent industry-wide research organization but that its study should include recommendations on the following specific proposed functions for such an organization:

- Appraising research opportunities and determine areas in which research is lagging, measured by research expenditures in other areas and the pace that would be warranted by prospective benefits.
- Serving as the instrument of the industry in sponsoring research projects of general importance.
- Providing liaison with the Federal Government on problems of allocation of Federal research efforts and of interrelation of private and public research efforts.
- Serving as a research clearinghouse for the entire industry, including scrutiny of defense and other research which might have application to the technology of the industry.
- Keeping abreast of research developments in other countries and making arrangements to take advantage of technological improvements adaptable to circumstances in the United States.

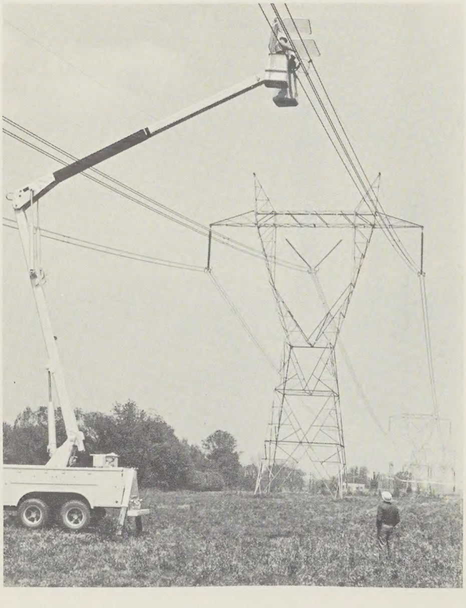

FIGURE 95 *Barehand maintenance of "hot" 750,000-volt test line of the Apple Grove Project of American Electric Power System and Westinghouse Manufacturing Co. is performed from a fiberglass insulated boom and bucket from which linemen can work safely and efficiently. This new technique was developed jointly with the Ohio Brass Co.*

The magnitude of power loads in the United States and the projections for continued major growth, the breadth of our resources for electric energy generation and the wide distribution of our load centers places this nation in a foremost position to benefit from major advances in the transmission of electric power. We mention this here, not with any thought of diminishing the importance of other related research needs, but to emphasize that this nation, which from all viewpoints stands to gain the most from cost reductions and efficiency improvements in electric transmission can afford to place itself in a position of contributing the most in advancing this technology. There have been indications recently of an acceleration of research efforts in the industry. We look to the forthcoming report of the Select Ad Hoc Research Committee to add impetus to these efforts which can provide such great benefits to the industry and the Nation.

Distribution

The distribution system is the customer's daily contact with the power industry. His opinion of the entire industry is based largely on the quality of service, the retail rates, and the aesthetic appearance of the distribution facilities.

The term "distribution system" refers to the lines and stations immediately related to the residential and comercial customers' premises. There are no clear voltage level distinctions, although the facilities tend to be lower in voltage than the transmission lines supplying them. There are three voltage levels normally involved: (1) "Subtransmission" voltage employed in connecting the supply point on the transmission network to the distribution substations; (2) "Primary" distribution voltage used on feeder lines from the distribution substation to the line transformers; and (3) "Utilization" voltage for lines from the neighborhood transformer to the customer's premises.

As the demand for power has grown, the utilities have increased their distribution investment per customer, not only to provide for the increased load but to improve the quality of service and attractiveness of the facilities. Heavier use has permitted lower average cost per kilowatt-hour and declining rates in spite of the greater total capital investment.

Public insistence for placing distribution lines underground is increasing. Remarkable strides are being made toward reducing the cost of underground facilities. For example, on one system the extra cost today for underground service in new developments as compared with overhead service is one-fifth of the excess cost which was required in 1947. Where circumstances are favorable, as in new residential developments built on subsoil which permits easy trenching, the additional cost of installing underground residential service may be less than $200 per home, or less than 50 percent above the cost for overhead construction. For homes costing $15,000 to $20,000 or more, this modest extra cost is well justified. Within 10 years practically all new housing areas and commercial centers probably will be supplied underground, although the primary circuits bringing power into these areas may continue to be overhead.

Underground distribution in new subdivisions may cause the older, established areas to seek similar treatment. However, the cost of converting from overhead to underground in a developed area is likely to be prohibitive. The streets, sidewalks, curbs, landscaping, water pipes, sewers, gas mains, and other obstacles could make the installation extremely expensive. Thus a real need remains for continuing improvement in the appearance of overhead services.

FIGURE 96 *Rural customers of Dairyland Power Cooperative receive power via 161 kilovolt main line transmission (right background) and 34.5 kilovolt main line distribution (in left foreground).*

The steady increase in load per customer requires constantly higher capacity circuits. Primary distribution circuits of 2,300 volts were considered optimum a few years ago, but today 12,000, 33,000 and even 69,000 volts are considered standard in many areas. Commercial and industrial loads are often supplied at the higher voltages and high-rise apartment buildings frequently are supplied through high-voltage circuits of 480 to 12,000 volts, but the single-family residential service has not changed from the 120/240-volt level. As stated by the Advisory Committee on Distribution:

> "Millions of lights and small appliances have been designed and built for 120 volts. . . . Analysis of the load-growth problem immediately shows that lighting and convenience outlets need not be a limiting element in the selection of secondary, or utilization, voltages. These features do not represent any real contribution to the high load densities with which the industry is faced. . . . The increasing loads found on distribution circuits today are largely associated with either built-in or relatively fixed appliances. . . . The comparatively recent development of dry-type transformers permits the separation of the 120-volt utilization problem from that of selecting a satisfactory secondary distribution voltage." [7]

The Advisory Committee has pointed up an important factor in the design of distribution systems in the future. With an increasing number of all-electric homes and increasing load density, low secondary voltages will be a serious handicap in the development of lower cost residential distribution service.

A solution which appears increasingly feasible would be to supply the home at a higher voltage, such as 480 volts, to be used directly for large, built-in appliances, and to provide the small dry-type transformer to reduce the supply to 120 volts for the conventional lighting and convenience outlet circuits. In many of the European countries the maximum voltage being supplied to the homes is gradually being standardized in the 400- to 500-volt range. Advisory Committee Report No. 23 discusses this proposal more extensively, and the industry should give serious consideration to further studies relating to the problems and benefits which would accrue.

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[7] Advisory Committee Report No. 23, p. 399 of Part II.

The distribution function of the electric industry is, in various ways, the most complex and versatile of the three principal functions. Distribution is not dealt with extensively in this report because the National Power Survey has been directed primarily to the generation and transmission functions which are more closely related to the regional and national aspects of electric power system development. Distribution costs represent approximately 40 percent of the delivered cost of power. Substantial reductions in the unit cost of the distribution function can occur from future load growth, because investment costs tend to rise only moderately with major increases in load. This economic relationship fits in well with the object of the Survey, which is to stimulate load growth through improved operations and coordination, and consequently lower rates. In fact, savings in distribution costs per kilowatt-hour which will result in turn from future load growth may well account for the largest cost reduction of any category—and thus go far toward enabling the Survey's projected 1980 price goals to be met.

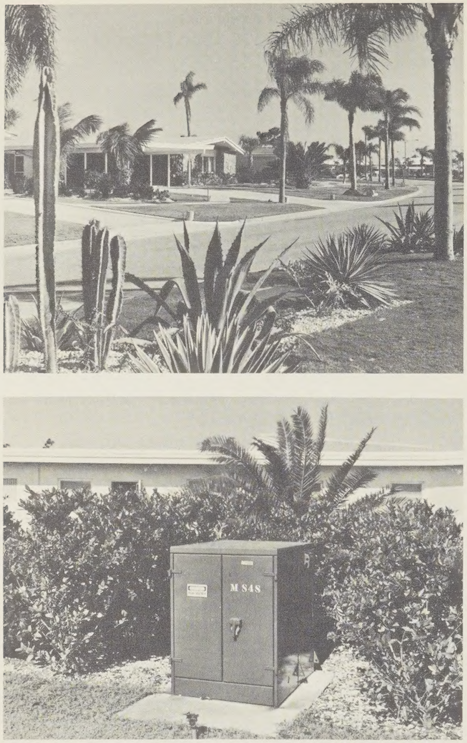

FIGURE 97 *Underground distribution lines leave the landscape practically unmarred. The only above-ground structures are occasional small housings for transformers and control facilities.*

CHAPTER 11

INTERCONNECTED SYSTEM OPERATION AND AUTOMATION

Most electric power systems in the United States are intertied with their neighbors to some degree, and the mutual support provided in case of trouble is largely responsible for the excellent standard of service established by the U.S. electric industry. Today an interconnected group of power systems covering 39 Central and Eastern States and 2 Canadian provinces, are intertied sufficiently to enable their 165 million kilowatts of electrical generation to operate in parallel (in synchronism).[1] These existing interconnections though in many cases of relatively small capacity sufficient for emergencies only, are a good beginning for the full coordination which the Survey visualizes in the coming decades.

This chapter is confined to the technical requirements for operating control of interconnected systems, and also summarizes the progress and future requirements in developing and applying control equipment and techniques. The benefits which can be gained by interconnection and coordinated planning and operation are evaluated from various standpoints in chapters 12 through 17.

Interconnection Control Problems

Electrical energy cannot be stored in an operating electric power system. The power consumed at any time must be matched by the aggregate power being generated. While each customer controls his own requirements by the flick of a switch, the erratic and abrupt change in power requirements of an individual residential customer cannot be matched by a corresponding starting or stopping of supplying generators because one modern generating unit may supply power for hundreds of thousands of customers. The needs of thousands, even millions, of customers served by a single power system change continuously and the total integrated load must be met by varying the quantity of power produced. Since changes in generation level cannot be made instantaneously, a continuing but usually insignificantly small fluctuation in the system frequency results. Adequate controls for frequency regulations are thus a key element in interconnected system operations.

For large interconnected systems in the United States the maximum frequency fluctuation during an average day will be less than $\frac{1}{10}$ of 1 percent above or below the mean value of 60 cycles per second. In the case of the large interconnected systems group already mentioned a sudden load change of about 2,300,000 kilowatts is required to cause a frequency deviation of $\frac{1}{10}$ cycle per second.

In an interconnected network, electrical energy tends to flow to the point of demand. Changes in load, therefore, alter (and may reverse) the flow of power over the interties. This flow is sensed by instruments that initiate control changes to restore the original balance. The sensitivity and the rate of response to the controls, with respect to the rate of change in the load pattern, to a large extent determines the magnitude of frequency fluctuations.

The extension of interconnection has been a gradual process in the United States. Difficult technical problems were solved as they arose by refinement of equipment, by new concepts for system analysis, and by modification of operating practices. By the late 1920's it became evident that close frequency regulation was a prerequisite to controlling the interchange of power between systems. This was first unsuccessfully attempted by manual control of prime mover governors but later solved by automatic control equipment.

The stability of systems operating in parallel was another problem that was faced and solved. Faults on transmission lines due to lightning or other causes and troubles in power plants frequently led to unstable conditions that at times would open tie-lines and split up the system. This was remedied by developing generator excitation systems with faster response, very high speed relays, and circuit breakers to rapidly remove the facility in trouble. The lightning arrester, the ultra-rapid reclosing of transmission lines after a fault, the synchronous condensor and other equipment along with carrier current and later microwave communication all played important parts in making present day interconnected system operation a reliable reality.

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[1] The terms "frequency" and "synchronism" derive from the fact that alternating electric power reverses direction 120 times per second (corresponding to 60 cycles). Systems whose frequencies are exactly equal may be electrically joined in synchronous operation and are said to be in "parallel."

The complexity of systems with interconnections at many points and various voltages created problems which could not be solved by slide rule or calculator. Electrical miniature models called network analyzers or analogs and more recently large scale digital computers, thus became essential tools of the system designer. The components of large systems are represented on the analog computer by electrical units which are readily modified and reconnected in various ways to study alternative methods of expansion. Today the network analyzer is being replaced by the digital computer because of the latter's greater speed and flexibility.

Coordinated Operation

As systems began experimenting with parallel, or synchronous, operation some 40 years ago, the poor frequency regulation in terms of today's standards produced swings in tie-line power flows which were difficult to control by manual regulation of the prime mover governors. Scheduled transfers between systems could not be maintained and in some instances the power actually flowed in the opposite direction from that scheduled. A period followed in which manual control was replaced by automatic frequency control at a master station. This was unsatisfactory because it placed an undue burden on the regulating station and did not solve the tie-line problem. Out of these attempts a method of operation evolved known as "tie-line frequency bias control", which, with improved governor controls, makes today's extensive networks feasible.

The basic principles of normal operation are twofold: (1) Each control area must provide generation for its own load or schedule power imports over its interconnections; and (2) each control area must share responsibility for the regulation of frequency on an assigned basis.

With respect to the first requirement it might appear that a utility could meter all of its load requirements, total all readings, and adjust generation to match the requirements. This is not practical. Rather, an indirect method is used. All tie-line power flows are telemetered to a control area center to produce a moment-to-moment indication of the net flow in or out. The net power flow in relation to scheduled power interchange reveals whether the area generation is more or less than required. The governors are instructed accordingly.

With respect to frequency control, it is inherent that the continual changes in load are accompanied by deviation from the exact 60 cycles per second. The governors respond to the deviation by a predetermined amount which is related to each system's capability. It is expressed in megawatts per $1/10$th of a cycle per second deviation and is referred to as frequency bias. For example, if a system has a frequency bias setting of 100 megawatts and the frequency falls to 59.99 ($1/100$th of a cycle low) the governors will add 10 megawatts of generation, raising the net power flow on the intertie by this amount until the frequency is restored to normal.

Area Analysis

For an orderly approach in the National Power Survey analyses, the United States was divided into 16 Coordination Study Areas. It was assumed that each of these areas, or similar geographic subdivisions, could be fully coordinated by 1970. It now appears that this objective will be realized if the present trend toward more extensive pooling continues. Since the United States has over 200 major systems or pools, achieving this degree of coordination by that time will be an impressive accomplishment. From 1970 to 1980, further pooling of dispatching and planning functions is expected.

An aid to coordinated operation is the North American Power Systems Interconnection Committee organization which has representatives from all sections of the United States and Canada. This organization meets twice a year to review operating problems associated with the interconnected systems and to agree on control standards to be adopted by other areas when they become a part of a large interconnected group.

Economic Dispatching

With a large number of generating plants operating in parallel, a central dispatcher must select the unit which will most economically supply the next increment of projected load, or, when the loads are decreasing, he must determine the best unit to take a reduction in load or to shutdown. These decisions are influenced by the production cost of the individual generators, the transmission connections to the load being supplied, any commitments to import or export power to adjoining systems, and, in the case of hydro generators, storage and streamflow conditions. Modern computer programs have been devised which provide for evaluating all of these variables and selecting the most favorable generation to be used. The savings in fuel cost in a large system have paid for the necessary computer in a few years.[2] Such computers, not only can perform calculating functions, but are also able to provide the operators with current operating cost data, log the operating performance record, provide a basis for decisions as to interchange of power with other members of a pool, and provide the billing information for intercompany accounting.

The complexities of modern electrical networks practically preclude an absorption of all necessary data by human dispatchers, particularly when rapid response is necessary during emergency situations or rapid changes in load requirements.

Unit Controls

Improving controls for the operation of the large steam-electric generating units that are being added on modern interconnected systems is an important adjunct to maximizing the overall interconnected operation. A generator prime mover normally has governing equipment which controls the flow of energy (e.g., steam to the turbine), in response to speed and load changes. As system load increases, the result is a slight drop in system speed or frequency and the governors operate to admit more energy to the prime movers to match the new load. The reverse happens when load decreases. Manual or automatic control is required to adjust the governor mechanism to restore speed to normal after a load change.

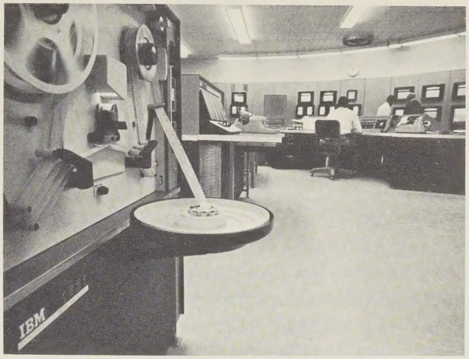

FIGURE 98 *This computerized dispatch center of the Public Service Co. of New Mexico controls five turbine generators in two stations with total generating capacity of 334 megawatts.*

In some recent cases, provision has been made for completely automatic control during startup and shutdown. Provisions are included for sensing abnormal values and for initiating action to remove the jeopardy or shut down the unit. The operator can take over from the automatic equipment or adjust controls to change the performance level and, in general, substitute his own judgment for the programmed response of the automatic device.

In recent years, more sophisticated controls have been achieved by monitoring many more factors and using regulating devices that operate within closer limits.

For plants burning coal, additional development is required before full automation will be possible. In the case of gas and oil-fired plants, the problems are less difficult and consequently automation has first been applied to these plants.

The estimated cost of completely automating a steam plant ranges from $1 million to $2 million, which is less than 3 percent of the cost of a 500-megawatt plant, and a lower percentage for larger plants. Approximately 15 of the new steam plant installations are incorporating equipment for full computer control.

A modern 500-megawatt thermal generating plant may have more than 400 items of information being fed into the control room. Some 250 of these items are in a category of operational information. Many are interrelated and must be monitored in order to arrive at intelligent response action. A computer can be programmed to select the proper corrective action to be taken in emergencies as well as to control the rate and sequence of operations during changes in a process such as startup and shutdown. Also it can integrate many items of information into a form more readily intelligible to the operator. Today, data logging and computer systems perform all of these functions to some degree.

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[2] In the United States some 140 systems have some form of automatic system control and over 40 have computers to do economic dispatch. Most of the latter were installed in the last decade.

Safety

As with all automated applications, the degree of reliability of remote unit controls in relation to human performance is a legitimate question. The computer designers have recognized this factor and built into their systems many "fail safe" characteristics. For example, the computer in a steam generating plant does not actually perform any of the adjustment functions but, rather, instructs other equipment which then makes the changes. It further monitors the auxiliary equipment to insure that the instructions are carried out. If the computer fails, the auxiliary circuits normally maintain the latest setting, and, in some cases, a subsequent program automatically returns the process to some known, safe operating conditions. The current status of the art is such that a satisfactory degree of reliability may be obtained with present hardware.

Communications

With interconnections and automated operation, fast, reliable, and accurate communication is essential. The central dispatch point must have continuous information on power flows, generation, voltage and other parameters, as well as the status of all portions of the network. In addition to the usual voice communication by telephone and broadcast radio, the utility requires a large and complex network for telemetering, circuit protection, and control functions.

A form of communication which is unique to electric power systems is carrier telephony. The transmission line circuits act as a guide for high frequency waves similar to ordinary radio. This system is remarkably economical since no modification of the transmission line is required other than to install a device for coupling the carrier current to the line and duplicate facilities at the receiving point. Also, the circuits are highly reliable as the physical construction of the transmission lines is very sturdy. In addition to carrier, however, extensive use is made of conventional wire circuits and beamed microwave networks.

Telemetering is an integral element of automatic generation control and economic dispatch by computers. The cost of communication channels for large pooling operations is normally less than 1 percent of the associated transmission investment.

Future Applications

Automatic control and operation with computers have been developed to a very sophisticated degree, but several years will be required to attain full application in the electric utility industry. By 1980, most plants and major systems will probably be under automatic dispatch and control. This will require a substantial investment, merely to keep up with new additions, and major expenditures to add this feature to present installations.

A fully coordinated power pool with automatic control for all phases of operation has yet to be

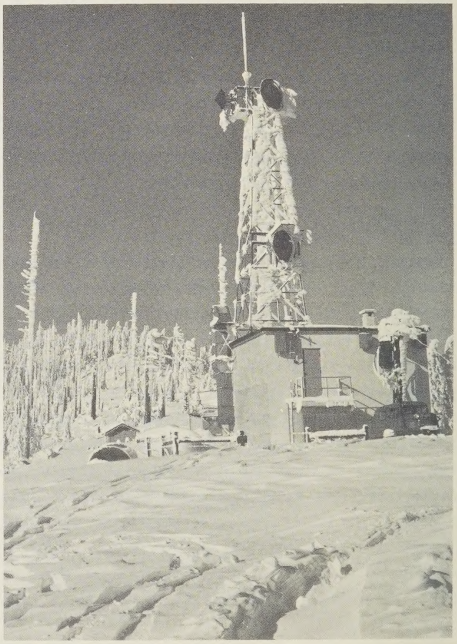

Figure 99 *The Microwave Relay Station on Augspurger Mountain in the Columbia River gorge area near Portland, Oregon, is a link in the Bonneville Power Administration communications network. Heated reflectors assure continuity of supervisory control, relaying and communication services under adverse weather conditions.*

realized. This would encompass not only economic dispatch but also assignment of spinning reserve, and free-flowing power over all tie lines. Likewise, capacity additions and network extension would be planned in terms of a complete single system concept. Such a development might involve computer control of the individual systems on a satellite basis with overall pooling control from a central dispatch center. On the other hand, computer technology is developing so rapidly that, with computers virtually able to talk to each other, it is possible we can in the future have the best of two worlds, namely, local dispatch computers operating in concert throughout wide regions to obtain the economic equivalent of centralized dispatching but able to operate independently if communications or tie-lines fail.

Nearly half of the cost of power to the customer is represented by the distribution and administrative expenses. The distribution component represents a substantial capital investment. Remote monitoring of system loads, possibly down to the individual customer's service with all data feeding into a central computer, has been suggested as a means for optimizing distribution network development and alerting the engineers as to critical areas requiring transformer changeouts and revisions of protective devices. A number of systems today use computers to derive transformer loadings from individual customer billing data and issue field orders to replace those transformers which appear to be under-loaded or over-loaded.

Summary and Conclusions

There are no insurmountable obstacles to the successful operation of large interconnected systems. Control equipment and techniques, particularly during the last decade, have demonstrated that large networks can be operated in parallel with a high degree of operating stability. The development of improved sensing devices coupled with the application of computers has greatly expanded the opportunity for the most efficient use of the generating and transmission facilities of an interconnected and coordinated pool. The transmission of much operating and control data between many points on an interconnected system is essential, but the required communication techniques and facilities are available for these expanded needs. An increasing dependence is being placed on automated controls made possible by the recent great advances in electronic devices.

CHAPTER 12

GENERAL CONCEPTS OF COORDINATION

A key characteristic of the electric power industry is that electricity must be available continuously and instantaneously in whatever amounts customers may demand. The electric utility industry through many decades has constantly improved the quality of its service to its customers and today sets very high service standards. It is no less a public utility responsibility that customers be served at the lowest possible cost—a cost which reflects every economic advantage within practical reach. This chapter outlines the economic advantages of coordination among electric utilities.

Evolutionary advances in the technology of power systems equipment justify the prediction that substantial reductions can be made in the cost of power in the several decades ahead. These advances, many of which have been mentioned in earlier chapters, pervade all phases of power system design and operation. Some of them, especially in the field of distribution, are achievable independently by each electric system, large or small. Many of the advances, however, will be related to scale, and can be fully effective only if the industry coordinates the power supply of whole groups of systems on an area, regionwide, or even nationwide basis.

Intersystem Coordination

While the planning of most systems to date has largely proceeded on a local basis, much has been achieved by the power industry, particularly in recent years, in power supply planning that looks beyond the boundaries of a single system. Utility managers are becoming increasingly cognizant that substantial reductions in power supply costs can be achieved through coordinated intersystem planning, construction and operation. What is now needed is acceleration of the trend toward increasingly comprehensive coordination over expanding geographic areas.

Coordination is a vehicle by which groups of electrical systems through common action can obtain the benefits of economy of size in the planning and development of sources of power supply and transmission. There are two essential prerequisites for full coordination. One is the construction of adequate transmission line interties and associated equipment to permit an uninterrupted and economical flow of electric energy throughout the electric network. The second is intersystem planning and the formulation of agreements between the interconnected systems to take full advantage of all of the economic opportunities for the construction and operation of facilities that will result in the lowest overall cost of power, with equitable sharing of the costs and benefits.

Coordinated intersystem planning of capacity requirements to supply diversified regional loads will enable the utilities to meet the same demand for electricity with a significant savings in generating capacity. The savings result from taking advantage of diversities in the loads of the participating systems and from reduced requirements for reserves. Capacity can be shared among the coordinating utilities to meet the coincident peak demand of the regional load, thus taking advantage of load diversity between systems, and providing savings which are discussed more fully in chapter 13. Also, intersystem planning makes possible reductions in total generating reserve requirements in several ways. Smaller reserves are needed for unscheduled generator or transmission outages. Reserves for scheduled maintenance can also be reduced through coordinated maintenance schedules, with larger pools of capacity thus available to meet unscheduled outages or to serve other purposes. Moreover, standby reserves for meeting unpredicted growth in loads may be smaller. These savings in reserves through coordination are discussed in detail in chapter 14.

Regional and inter-regional coordination also makes it possible to utilize larger and more economical generating units which are operated at higher load factors and produce electricity at the lowest possible cost per kilowatt-hour. Once the systems in a broad area are intertied with a large capacity transmission system there are further benefits in selecting the optimum plant types and locations, cheapest fuel sources and lowest fuel transportation costs, and most economical plant design and construction. Local limitations on fuel sources, water supplies and air pollution, any of which may involve economic penalties, become less controlling.

Coordination at All Levels

The need for effective intersystem coordination is not limited to the major utility systems of the country. The smaller systems, especially those now operating in virtual isolation, also have much to gain from coordination. Successful coordination over broad areas of the nation must begin with a coordination in smaller units. For example, extensive "coordination" comes into being almost automatically within large systems under single ownership or management. The next step in coordination is in the formation of "pools" of two to a dozen or more systems in close proximity with one another, including small municipal systems, cooperatives and local investor-owned systems. The combined assets, loads, reserves and bargaining power of these pools, enable them to participate with their contiguous neighbors in a larger network in order to receive the further benefits that may be afforded by coordination on an expanded scale.

The achievement of full industry-wide coordination will not be achieved automatically. It will require a spirit of enterprise and cooperation by all concerned and an equitable sharing of responsibilities, costs and benefits. The potential role of small systems in a fully coordinated national power supply receives detailed analysis in chapter 16.

Economies from Coordinated Planning

Most of the benefits of full coordination arise from reduced overall generating capacity requirements and the lower unit costs achievable in the planning and construction of new facilities. When one considers that the Nation might require more than 500 million kilowatts of capacity by 1980, every 1 percent capacity saving amounts to a $500 million saving for the consumers who must ultimately bear the cost. The more important opportunities for such economic gains are described below.

Load Diversity

The simultaneous peak load of a group of systems is almost always less than the sum of their separate noncoincident peaks, owing to differences in types of load served, time zone differences, and diversity resulting from seasonal variations in loads. In 1960, the sum of the individual system peaks for the contiguous United States was nearly 12 percent higher than the national coincident peak. Strong interconnections to permit the sharing of capacity to meet the individual peaks results in a reduced total capacity requirement. These relationships are more fully discussed in chapter 13, which presents estimates of the diversity savings to be expected from stronger interconnections.

Reserve Generating Capacity

Reserve generating capacity is needed to provide a margin of protection against two major contingencies: breakdowns of generating units and underestimates in the load forecasts upon which capacity planning had been based. Additional reserves may also be needed to cover scheduled maintenance and in some cases, transmission outages.

By sharing reserves through interconnections, a group of systems can reduce the combined reserve for unscheduled outages, since it is unlikely that maximum outages of units on all systems will occur at precisely the same times. The pooling of reserves is based on the same principle as that offered through the pooling of risks by insurance companies. The use of large, economical units increases the importance of reserve pooling because each system should have access to a reserve at least as large as its largest unit.

The analysis presented in chapter 14 suggests that the 1980 reserve requirement for forced outages associated with the large unit sizes which are economical with full coordination would be only about 8 percent of the peak with nationwide pooling of reserves but with the same units would be 17 percent, or more than twice as great, if reserves are pooled separately in the 16 Coordination Study Areas. Interconnected systems can also share reserve capacity for load forecasting errors by pooling their load estimates, since errors in forecasts independently made by the individual systems may be partially offsetting. For the Nation as a whole this saving is estimated to be about three percent of the peak load. Chapter 14 discusses in detail the reserve savings made possible by increased interconnection.

Size of Steam-Electric Generating Units

By scheduling new generating capacity to meet their combined load growth, systems which coordinate their expansions are able to install larger and more economical units than they could justify separately. A 1 million-kilowatt coal-burning unit should show savings of 20 percent to 30 percent in capital costs per kilowatt over a similar 100,000-kilowatt unit. Under base load operating conditions the corresponding savings in generation costs per kilowatt-hour, including fuel, should be about 30 to 40 percent. A large new unit is put to use more quickly when it is used to meet the combined load of a large pool, and the extra reserve requirement associated with increased unit size is minimized by the sharing of reserves through interconnections. Large generating plants can bring further savings of large magnitude from the use of such large-scale, low-cost means of fuel transportation as the integral train. The savings in lower cost fuel transportation available at large plants can double or even triple the savings resulting from the increased efficiency of the plants.

Location of New Generation and Transmission Capacity

Large generating units and strong interconnections do not in themselves constitute full coordination: power stations and transmission lines must also be properly located with relation to the combined service areas of the systems involved. The interlocking, irregular service area patterns of the major utility systems make this aspect of coordination particularly important.

The most economical generating sites for serving one system's load are often located in another system's service area, and the most economical backbone transmission pattern for a group of systems almost inevitably cuts across individual service areas. For example, the Virginia Electric and Power Co. is constructing a 500-kilovolt AC transmission loop to connect its mine-mouth generating plant now being built outside of its service area near Mount Storm, W. Va., with its existing network. This 350-mile circuit will become part of a major network interconnecting the company's system with neighboring systems to the north and the south. Subtransmission lines of fully coordinated systems may also involve numerous lower voltage interconnections and tapoffs where it is most economical to serve part of the distribution area of a system from the subtransmission lines of another system.

Planning Peaking Sources

Planning of peaking capacity on a joint basis may result in justifying very large new and expanded hydro installations, pumped storage or thermal peaking plants, which will carry the load peaks of a group of utilities at much lower unit cost than if each utility had tried to supply its own peaking capacity. The Niagara Power Project of the Power Authority of the State of New York illustrates the unique use of pumped storage facilities for increasing the peaking capacity of the plant. The United States and Canada have agreed for scenic purposes to maintain a minimum flow of 100,000 cubic feet per second over the falls during daylight hours (bypassing the turbines) and to allow this flow to be reduced to 50,000 cubic feet per second during the night. Thus the allowable use of the Niagara River for power generation is greater during the night hours but the need for power is greater during the day. The unneeded flow is therefore pumped up to an artificially created reservoir at night and as added capacity is needed on the following day, the stored water is released through the reversible pump-turbine units which can develop 240,000 additional kilowatts. The same water then flows through the main Niagara plant. The companion plant of The Hydro-Electric Power Commission of Ontario is similarly arranged. These arrangements are based upon the availability of the peaking power to a large power pool.

Most Economical Planning and Operation of Hydroelectric Resources

The coordinated planning and operation of hydroelectric facilities in a river basin, a concept now rather commonly accepted, can yield large benefits compared to non-coordinated developments. The interconnection of two or more areas which have hydroelectric facilities will frequently yield added firm power or dependable capacity because of diversity in streamflow patterns.

In addition, interconnection of hydro-based systems with thermally based systems can result in fuel

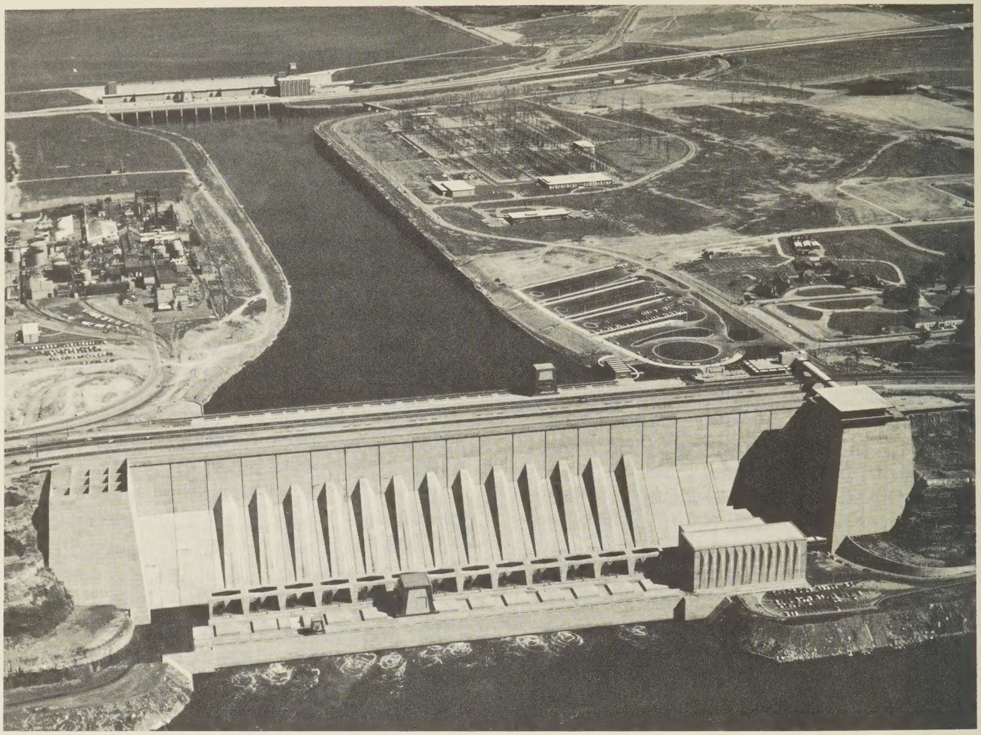

FIGURE 100 *The Robert Moses Niagara Power Plant of the Power Authority of the State of New York houses thirteen 150,000 kilowatt hydro generators, largest ever built in the United States. The 12 units in the Lewiston Generating Plant, background, are operated as 37,500 horsepower motor pumps to fill the reservoir at night when extra Niagara River flow is available and as 20,000 kilowatt generators for added peaking capacity during the daytime. Total installed capacity in this two-dam project is 2,190,000 kilowatts.*

saving through utilization of surplus hydroelectric generation during high river flows. At times of low flow, off-peak thermal generation can supply the energy needed to maintain a given level of dependable hydroelectric capacity.

For example in 1941 TVA and the Aluminum Co. of America entered into agreement whereby TVA would operate the two systems as though all the plants were members of the same system. The Aluminum Co. receives as a minimum as much power as their plants would have produced under the most efficient independent operation and shares in the added power produced under the coordinated plan of operation. This arrangement has worked well for both parties and was renewed with minor modifications on a long-term basis in 1962.

Coordinated Dispatching

Full coordination of dispatching allocates the total load of the combined systems among individual units in the most economical manner. This requires that each increase in total load be met with the smallest possible increment of operating costs to the combined systems. Maximum savings in production costs can be realized only when the combined systems follow substantially the same criteria and procedures for exchanging economy energy (energy which the receiving system could supply from its own resources, but at greater cost) as they do for the dispatching within their own systems. This necessarily involves not only the operation of steam-electric units but also the timing of hydroelectric and pumped storage reservoir releases. The increasing sophistication of computers and automatic control equipment has improved the effectiveness of dispatching to the point where fully coordinated dispatching is now feasible. The prospect that computers and control techniques may change markedly in coming years makes it difficult to predict the mechanics of coordinated dispatching for large areas in the future.

The P-J-M[1] power pool, a closely interconnected group of 9 nonaffiliated systems, was among the foremost in the early application of economic dispatch equipment. Information continually and automatically supplied to a central dispatching office in Philadelphia and processed by a digital computer, which is programmed to account for all significant variables in cost of generation and transmission, controls the selection and loading of the units in the entire pool, minute by minute. The capacity of the pool network is such that capacity from any generating unit is available for selection to serve loads as needed anywhere in the pool area.

Maintenance Scheduling

All generating units must be taken out of service periodically for maintenance. The frequency and length of the out of service period depends upon the type, age and size of the unit. The close coordination of systems can have two opposing effects on the program of unit maintenance. As system loads are combined, the relative spread between the peaks and the valleys of the load decreases and thus the amount of daily and seasonal offpeak time available for maintenance is reduced. This effect can be observed in figure 102 of the next chapter in comparing the relatively large magnitude of seasonal valleys of the two individual load curves with the smaller valleys of the combined load curves. However, through coordinated planning of maintenance among the interconnected systems, programs can be arranged to minimize the aggregate capacity of base load units which are removed for maintenance at any one time. Such coordination helps minimize the amount of generating capacity needed solely for maintenance. This subject is discussed in greater detail in chapter 14 and estimates are included on the capacity required solely for maintenance for various levels of coordination.

Operating Reserves

Interconnected operation requires a sharing in the responsibility for providing "spinning" reserve needed to provide for sudden increase in load or loss of equipment. Coordinated operation reduces the need for spinning reserves just as it reduces the need for total reserves. In addition, it broadens the selection of equipment available to carry the spinning reserve.

Summary and Conclusions

The purpose of the Survey is to direct the industry toward the most economical means of supplying the nation's fast growing power needs, both short range and long range. The greatest total savings to all power users can be achieved only through planning which looks far beyond the requirements of a particular system or locality. Growing power requirements and technology demand that all electric utilities work closely together. Consumers are entitled to be served as economically as possible regardless of how ownership of the facilities may be shared among individual systems.

The industry has taken commendable steps in the direction of wider coordination. Wherever the parties show a willingness to work together a solution can be found to the complex problems involved in measuring and equitably sharing the benefits and burdens involved in such cooperative effort.

Full coordination will require large investments for added transmission lines and related facilities, including those needed for conveying energy supplies from larger generation centers and for the control systems needed for efficient large-scale interconnected operation. An attempt has been made in the following chapters, in a spirit of objectivity and without regard to differences and rivalries among the various segments of the industry, to set forth the benefits attainable through coordination, and to appraise the range of added costs which must be deducted from such benefits.

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[1] The Pennsylvania-New Jersey-Maryland Interconnection, *see* table 60 for participating companies.

CHAPTER 13

LOAD DIVERSITY AND CAPACITY NEEDS

Investment in generating capacity is a major component of the cost of electricity, and therefore it is important to minimize capacity needs.

By 1980, electric utilities can save billions of dollars in generating expenses by sharing load diversity through coordinated planning and operations. Load diversity occurs when peak loads for two power systems occur at different times. Without coordination, both systems would have to maintain sufficient generating capacity to meet their respective peaks. With coordinated operations, each system can supply part of the peak load of the other.

An interchange agreement about to be implemented between TVA and the South Central Electric Companies, will result in savings in capital investment of about $100 million. Widespread and increasingly attractive opportunities for such savings from power interchanges will appear in the future. We have estimated that the total amount of load diversity between individual power systems may reach 41 million kilowatts by 1980. Its utilization will require a major expansion in interchange agreements.

In this chapter, we have attempted to identify the order of magnitude of the savings to be achieved through diversity from increased coordination. We recognize the limitations of the data on which we have based our estimates of the various components of diversity. Nevertheless, due to the great interest in the likely amounts of these components of diversity, we have tried to indicate their approximate orders of magnitude.

Daytime industrial use of electric power versus evening residential uses and summertime air conditioning versus heating with electricity in winter are examples of loads which may be complementary in the sense that the heavy demands of one load do not occur simultaneously with those of the other. This nonsimultaneity, true in some degree for almost all loads, results in a peak value of total demand which is less than the sum of the peak demands of separate loads.

Gross savings accrue from both load diversity and from the other aspects of coordination and must be offset by the cost of necessary transmission to permit the transfer of capacity from one system to the other. Sound technical and economic analysis, aimed at overall optimization, must substantiate each step in the orderly development of the interconnected systems.

The Diversity Phenomenon

Precisely defined, load diversity as it affects capacity planning is the difference between (1) the sum of the separate peak loads of two or more load areas, for any given period, and (2) the coincident peak load of the combined areas within the same time period. Diversity may be expressed in kilowatts or as a percentage of the combined coincident load. Commonly the kilowatt peak demands upon which diversity analyses are based are expressed as average demands for the clock hour in which the peak occurs.

Customers' power demand patterns ordinarily recur with some degree of regularity or rhythm. Pronounced load variations which can be predicted include (1) the month-to-month variations resulting from seasonal weather cycles, (2) the hour-to-hour load changes which reflect the daylight-darkness cycle and the living and working habits of a community, which we classify as time zone and random diversity and (3) the variations occasioned by the pronounced difference between weekend and workweek demands. Since weekend load reductions affect all systems alike this third type of variation creates only a limited usable diversity. The only types of diversities which will be considered here are the first two—seasonal and time zone plus random diversity.

Seasonal Diversity

Seasonal diversity, sometimes called annual diversity, results primarily from variations in electric energy uses which are strongly influenced by the weather. Examples are summer air-conditioning loads (which may peak on almost any weekday between June and September) and winter heating loads which usually are at their maximum in December or January. One system or area may normally have a summer peak load while another system's peak may occur during the winter months, depending on local weather conditions, rate levels, and degrees of promotion of air conditioning and heating loads. Because of the large amounts of energy required for space heating, low rates and intensive promotion are especially important in determining space heating saturations.

Records of monthly peak loads for the years 1950 to 1960 inclusive were analyzed for each of the major systems in the 48 power supply areas. Trends in monthly peak over this 10-year period were used by the FPC staff as a guide to project monthly loads for 1970, 1975, and 1980. Some departure from a straight mathematical projection was introduced on a judgment basis in an attempt to recognize the effects of localized and temporary factors.

Figure 101 shows for each of the 48 FPC power supply areas the differences between the August and December peak requirements in 1970 and 1980.[1] These, as well as similar differences in 1960, are summarized below:

	Actual 1960	Projected	
		1970 [1]	1980 [1]
Excess of December over August loads:			
Gigawatts [2]	7. 75	16. 12	29. 68
Number of areas	(26)	(27)	(28)
Excess of August over December loads:			
Gigawatts [2]	7. 01	14. 65	22. 87
Number of areas	(22)	(21)	(20)

[1] Sums of the figures shown in figure 101.

[2] Millions of kilowatts.

As shown on the maps, mid-continent areas, particularly the south-central and southwestern part of the United States, have high summer peaks, while the areas of the Great Lakes and Northeastern States, the North-Central States and the Pacific Northwest generally have winter peaks. Seasonal power flows between areas with summer peaks and areas with winter peaks reduced capacity requirements in each. Further considerations affecting diversity interchanges, namely the monthly variation in hydroelectric capability, the decline in capability of steam plants in the summer due to warmer condensing water, and the requirements for off-peak maintenance, are discussed in chapter 14.

The large seasonal difference in load that exists between the Tennessee Valley Authority area and the area to the southwest served by the South Central Electric Cos. is an example of seasonal diversity of current interest. The 345-kilovolt and 500-kilovolt transmission lines now under construction (see fig. 126) have been planned to permit power transfers that will take advantage of much of the present diversity. The seasonal characteristics of the loads in the two areas complement each other so that under the exchange agreement the systems can produce and deliver power to the ultimate consumer at a lower cost. The peak loads for each month through 1970 for the systems in the two areas are shown as two separate curves and as a combined pattern in figure 102. If the areas remain separate, the total of the generating capacity in the two areas would have to be sufficient to meet the separate peak loads as they occur. The amount of capacity to cover the peak loads for two separate areas is given by the top curve in the illustration. A comparison of the top curve with the curve for the combined load clearly shows that additional capacity would be required if the loads are supplied separately. Through the interconnection agreement which has been made, however, diversity power flows are scheduled to reach 1,500 megawatts by 1968 and the savings in capital investment is expected to be about $100 million. The interconnection will also lead to a reduction in fuel costs through fuller use of the most economical generating units and will permit a reduction in reserve capacity by making it possible for the areas to help each other in time of emergency.

The 1980 map in figure 101 indicates a number of possibilities for similar seasonal interchange of

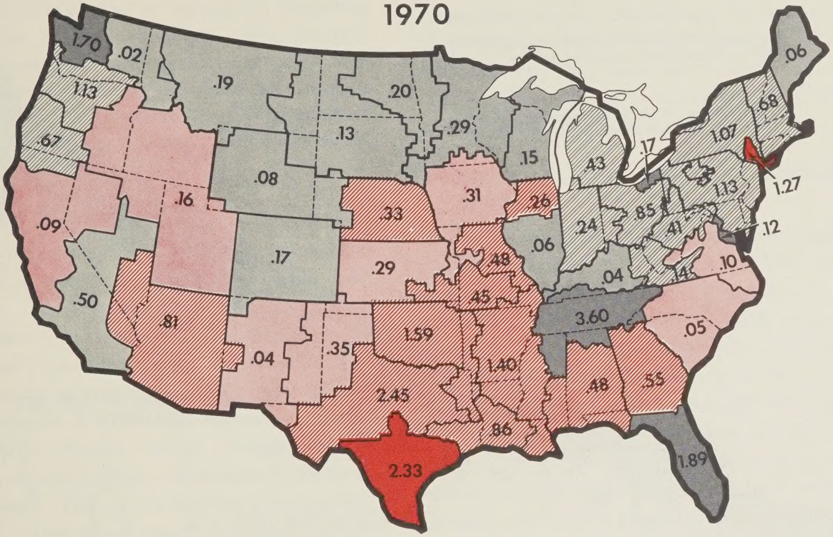
---

[1] August and December are used as the critical months for summer and winter peak loads. In individual areas, however, they do not necessarily represent all the seasonal diversity nor represent the changes from one year to the next. In the capacity analysis of chapter 14, data for each month throughout the year and for the summer and winter peaks of the preceding year were used.

ESTIMATED DIFFERENCES BETWEEN AUGUST AND DECEMBER PEAK LOADS

Within Each Power Supply Area

1970


1.70
.02
.19
.20
.06
1.13
.68
.13
.29
1.07
.67
.17
.15
.43
1.27
.08
.16
.33
.31
.26
.09
1.13
.85
.24
.41
.12
.06
.48
.10
.17
.29
.04
.14
.50
.45
3.60
.81
1.59
.05
.04
.35
1.40
.48
.55
2.45
.86
1.89
2.33

1980

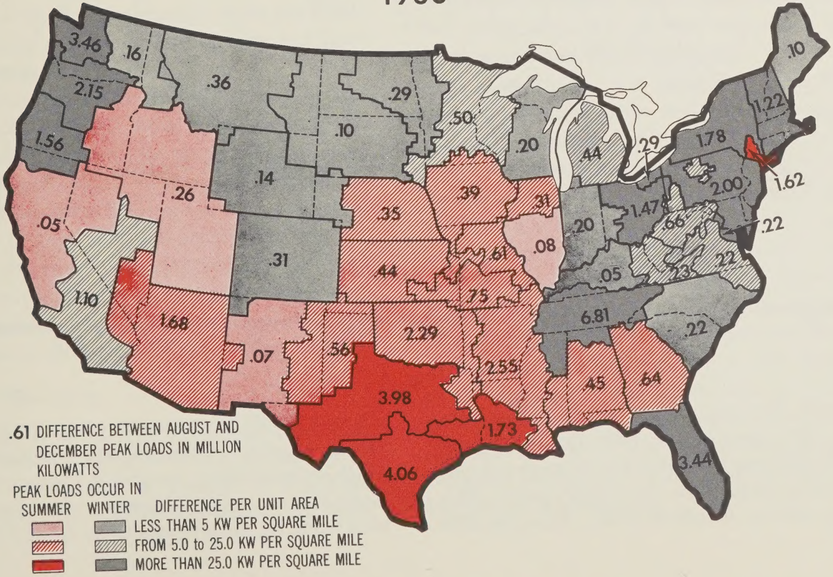
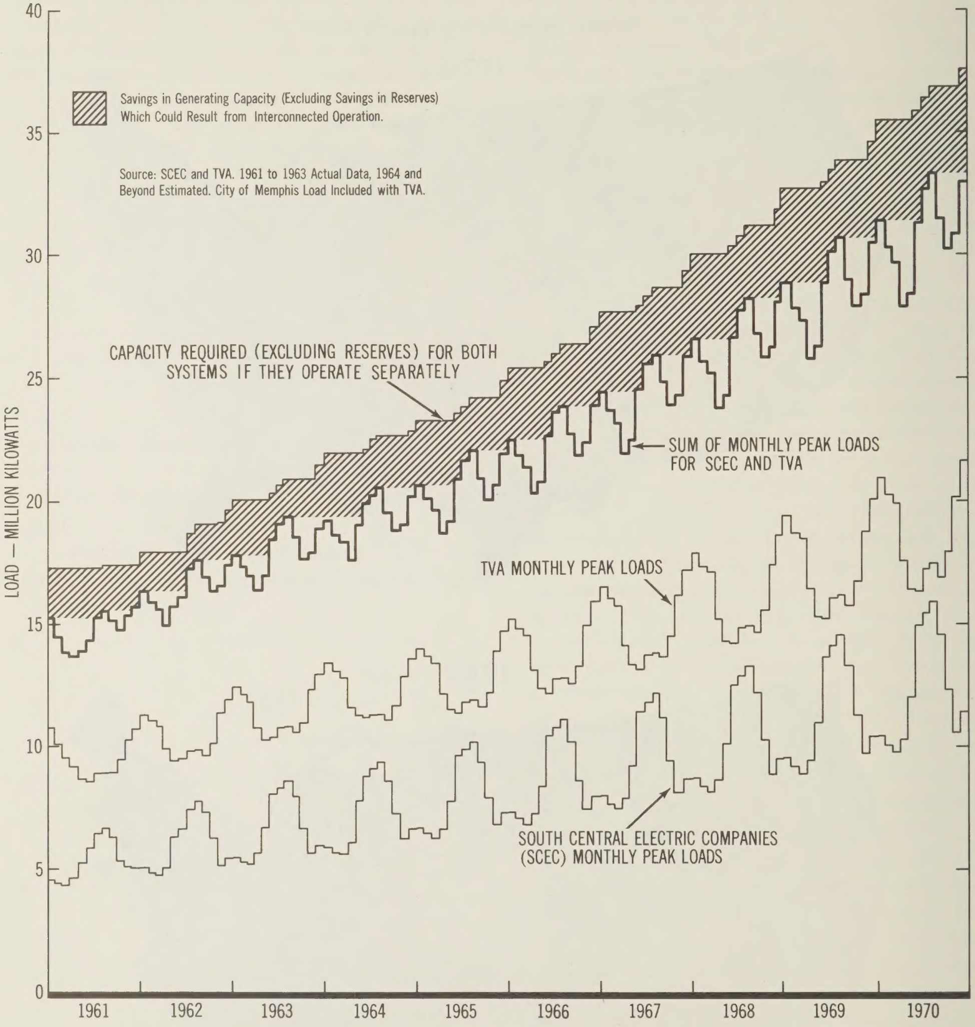

3.46
.16
.36
.10
.29
2.15
1.22
.50
.10
1.56
1.78
.20
.44
.29
1.62
.14
.39
.26
2.00
.35
.31
1.47
.05
.20
.66
.22
.61
.08
.31
.44
.22
.23
.05
1.10
.75
6.81
.22
1.68
2.29
.56
.07
2.55
.45
.64
3.98
1.73
3.44
4.06
.61 DIFFERENCE BETWEEN AUGUST AND DECEMBER PEAK LOADS IN MILLION KILOWATTS
PEAK LOADS OCCUR IN
SUMMER
WINTER
DIFFERENCE PER UNIT AREA
LESS THAN 5 KW PER SQUARE MILE
FROM 5.0 to 25.0 KW PER SQUARE MILE
MORE THAN 25.0 KW PER SQUARE MILE

FIGURE 101

POTENTIAL SAVINGS IN GENERATING CAPACITY RESULTING FROM SEASONAL DIVERSITY BETWEEN SCEC AND TVA



Source: SCEC and TVA. 1961 to 1963 Actual Data, 1964 and Beyond Estimated. City of Memphis Load Included with TVA.

Figure 102

power with resulting savings to the parties concerned. For example, the 1980 December peak of the Florida area is estimated to be some 3.4 million kilowatts larger than the August peak. This compares with 0.7 million in 1960. Thus, by 1980 this area should be an attractive partner for coordinating capacity exchanges with adjoining areas which are expected to continue to have substantially larger summer peaks. Arrangements recently have been made for the seasonal exchange of 100 megawatts of firm power between systems in Florida and those in adjoining States to the north.

In the two power supply areas lying in south and central Texas, the August peak in 1960 was 2 million kilowatts greater than the December peak. By 1980, it is estimated to exceed the December peak by some 8 million kilowatts. This diversity will be subject to possible exchange in 1980 with either the Northeast Sector and southern Ontario or the Pacific Northwest where the 1980 December peak in each case may be some 7 million kilowatts greater than the August peak.

Time Zone Diversity

The hour-by-hour load curves for individual power systems have considerable similarity in time and shape. Nevertheless, even with similar patterns the peak demands do not occur coincidentally in the nation's four time zones. An initial study of hourly loads for all systems across the country based on extrapolation of 1960 data, suggests a possible opportunity for capacity savings through east-west exchanges of power to take advantage of this time-zone diversity. This type of diversity is particularly in evidence in the winter months when marked system peaks tend to occur when lights are turned on at 5 or 6 p.m. and then fall off rapidly as stores, offices, and factories close. In summer this type of diversity is less because summer peaks are determined in large part by air conditioning and have longer duration.

To the extent that the coincident load for systems in each time zone tends to peak sharply at approximately the same time of day, by local time, a load diversity occurs between time zones. As observed by successive hours of Greenwich time the occurrence of peak demands moves from east to west with the sun. Consequently, through east-west interconnections across time-zone boundaries, the leading and lagging time-zone systems could render capacity asssistance to the zone at peak.

Random Diversity

This category of diversity includes all differences in timing and magnitude of area peak loads other than those attributable to seasonal or time-zone characteristics. Such differences include the effect of having a different type of industry in one area than another, variations in daily weather patterns over large geographic areas and the like. A detailed study of load pattern variations over an extended period of time may show that load reductions from random diversity can be dependable in large degree. In most load analyses a clear distinction between time zone and random diversity is not possible. In further discussion, therefore, they will be treated jointly.

Analysis of Time Zone and Random Diversity

The complete hourly loads for the first full week in April, August, and December of 1960 were examined in detail for each power supply area. The percentage diversity between systems within each of these 3 weeks is given in table 47, which also indicates the growth of diversity as areas are combined. For each of the 3 weeks for which the load was analyzed, the diversity (sum of the separate peak loads for the systems within an area as compared with the single peak if the loads were combined) within the power supply areas averaged about 1 percent; within the 16 Coordination Study Areas, about 1½ percent; within the eight FPC Statistical Regions, about 2 percent; within the four Coordination Sectors, about 3 percent; within the two zones, about 3½ percent, and within the 48 contiguous States, about 5 percent.

As shown in the first column in table 48, the diversity measured in the week starting August 7th was less, particularly between East and West Zones, than the diversity measured in the week starting December 4th. Applying the equivalent diversities, percentagewise, to the entire month, results in a diversity among peak loads of individual systems, as shown in the second column of 5 gigawatts in August and 8 gigawatts in December. The sum of August peak loads was 132 gigawatts, and with the estimated diversity this gives a coincident peak of 127 gigawatts. The August peak proved to be the largest coincident peak for the year; the 133 gigawatts sum of the December peak loads and the estimated diversity within that month yielded a peak load of only 124 gigawatts.

TABLE 47

Percentage Time Zone and Random Diversities Between Systems for 3 Weeks in 1960

	Apr. 3–9	Aug. 7–13	Dec. 4–10
Within power supply areas as a group (weighted average [1])	0.98	0.93	0.72
Within each coordination study area:			
A New England	1.17	1.32	0.56
B New York	4.88	2.22	0.52
C Pennsylvania-Jersey-Maryland	0.90	1.59	0.20
D Ohio Valley	1.07	1.78	1.66
E Carolinas-Virginia	1.47	0.68	1.24
F Tennessee Valley	1.13	0.34	0.64
G Southeastern	5.50	1.35	1.56
H Lower Michigan	0.00	0.89	1.04
I North Central	0.76	2.09	0.89
J Texas Area	0.76	2.16	0.87
K Middle South Area	1.30	2.81	1.63
L Upper Missouri Basin	1.07	5.68	2.67
M New Mexico and Panhandle	0.00	0.08	1.00
N Southwest	1.86	1.73	1.90
O Colorado-Wyoming Area	0.41	1.42	0.63
P Northwest	0.66	2.57	3.27
Weighted average [1]	1.59	1.73	1.28
Within each FPC statistical region:			
I Northeast Region	2.64	2.25	0.41
II East Central Region	0.86	1.61	2.00
III Southeast Region	3.74	0.92	2.58
IV North Central Region	0.76	2.10	0.90
V South Central Region	1.45	2.63	1.42
VI West Central Region	4.12	4.89	2.79
VII Northwest Region	0.66	2.58	3.28
VIII Southwest Region	1.86	1.73	1.90
Weighted average [1]	1.96	1.95	1.70
Within each NPS coordination study sector:			
Northeast Sector	2.73	1.95	1.15
North Central Sector	1.30	2.56	2.27
South Sector	5.58	3.26	3.36
West Sector	3.70	3.05	2.68
Weighted average [1]	3.48	2.62	2.20

See footnotes at end of table.

TABLE 47—Continued

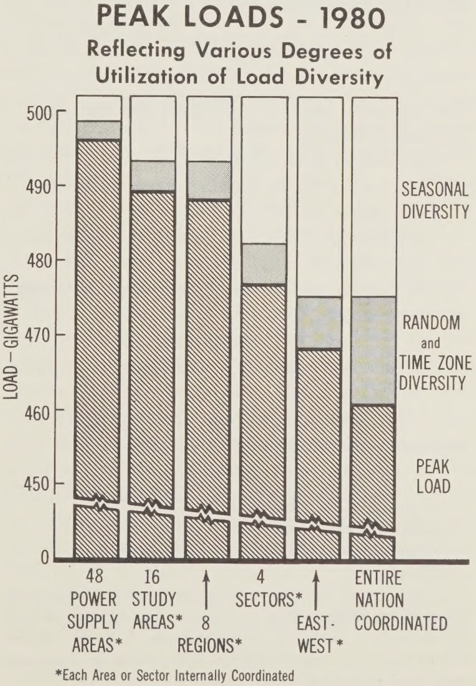
	Apr. 3–9	Aug. 7–13	Dec. 4–10
Within the east and west zones:			
East (three eastern sectors)	4. 29	3. 18	3. 40
West	3. 70	3. 05	2. 68
Weighted average [1]	4. 18	3. 16	3. 26
For the Nation as a whole [2]	5. 68	3. 86	6. 53

[1] Weighted according to peak loads for the week.

[2] Excluding Alaska and Hawaii.

In order to obtain some indication of future time zone and random diversities, the percentage diversities for the three 1960 weeks were projected to 1970 and 1980. While the general basis of this projection is considered valid, the record and analysis of trends in time zone and random diversities on a countrywide scale are very limited. For this reason, the projections used for 1970 and 1980, as given in table 48, have been taken as only one-half of the diversities which were calculated utilizing the 1960 determination in table 48 as the base. The result, as shown in the third column of the table, is an expected 1970 peak of 253 gigawatts occurring in August and, as shown in the fourth column, a 1980 peak of 461 gigawatts occurring in December.

Table 49 summarizes the potential reduction in the peak load by utilization of diversity. Figure 103 presents the same data in chart form, showing the diversity advantages that accrue from successive stages of coordination as applied to the projected load for 1980. If coordination were limited to each of the 48 power supply areas the sum of all the individual peaks of the various areas would total 496 gigawatts. With intersystem coordination expanded to cover all of the 48 contiguous States, the 1980 simultaneous peak requirement is estimated at 461 gigawatts. If these estimates prove accurate, potentially, a 7 percent reduction in the peak load, amounting to 35 gigawatts in 1980, could be realized. This capacity saving is partly offset (see table 53) by an increase in capacity of about 5 gigawatts for scheduled maintenance. The reduction in capital investment in generating capacity is also partly offset through additional transmission costs, but the net saving is in the order of 11 billion dollars. The estimates for 1980 are given in table 78, p. 286.



*Each Area or Sector Internally Coordinated

Figure 103

TABLE 48

Time Zone and Random Diversities for the United States [1]—1960, 1970, and 1980

(In Gigawatts [2])

	1960		1970	1980
Summer	**Aug. 7–13**	**Aug. 1–31**	**Aug. 1–31**	**Aug. 1–31**
Noncoincident peaks of individual systems	[3] 123.19	[4] 131.76	[4] 257.93	[4] 468.61
Estimated diversity:				
(1) Within power supply areas	1.13	1.21	1.19	2.16
(2) Among PSA's within coordination study areas	.97	1.03	1.00	1.83
(3) Among CSA's within FPC statistical regions	.19	.21	.21	.38
(4) Among regions within coordination study sectors	.86	.92	.90	1.64
(5) Among sectors in the east	.62	.66	.64	1.17
(6) Between east and west zones	.81	.87	.85	1.54
Total	[5] 4.58	[6] 4.90	[7] 4.79	[7] 8.72
Estimated coincident peak	118.61	126.86	253.14	459.89
Winter	**Dec. 4–10**	**Dec. 1–31**	**Dec. 1–31**	**Dec. 1–31**
Noncoincident peaks of individual systems	122.25	132.52	259.40	475.42
Estimated diversity				
(1) Within power supply areas	.87	.95	.94	1.71
(2) Among PSA's within coordination study areas	.67	.73	.71	1.31
(3) Among CSA's within FPC statistical regions	.49	.53	.52	.95
(4) Among regions within coordination study sectors	.59	.64	.62	1.14
(5) Among sectors in the east	1.24	1.34	1.31	2.40
(6) Between east and west zones	3.63	3.93	3.85	7.06
Total	[5] 7.49	[6] 8.12	[7] 7.95	[7] 14.57
Estimated coincident peaks	114.76	124.40	251.45	460.85

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[1] Excluding Alaska and Hawaii.

[2] Millions of kilowatts.

[3] Major systems only.

[4] All systems.

[5] Actual values from hourly data reported to the Federal Power Commission. Note for example that for August 7–13 the diversity among all major systems, 4.58 gw (shown above) may be compared with the 3.86 percent of coincident peak listed in table 47.

[6] Projected using the same diversity factors as measured for the one week within the month.

[7] Since no year-to-year trend in diversity is yet available from nationwide statistics, the diversities for August and December 1970 and 1980, were projected at one-half the values taken for 1960. The calculation is based on the coincidence factor which is the reciprocal of the diversity factor. For example, the coincidence for August 1960 is 3.72 percent, one-half of this value applied to 257.93 gw, the estimated noncoincident peak for 1970, yields the estimated diversity of 4.79 gw.

TABLE 49

Summary of Potential Reductions in Peak Load Through Utilization of Diversity—1980

(In gigawatts [1])

Extent of coordination among systems	Diversity: Seasonal	Diversity: Random and time zone	Sum of peak loads
Individual systems	....	......	502
48 power supply areas	3	3	496
16 coordination study areas	9	4	489
8 FPC statistical regions	9	5	488
4 coordination study sectors	20	5	477
2 east and west zones	27	7	468
Entire Nation coordinated.[2]	27	14	461

[1] Millions of kilowatts.

[2] Excluding Alaska and Hawaii.

System Load Factors

It is apparent from table 49, that a high degree of coordination and planning for use of diversity can produce major savings in generating capacity investments. Although capacity is saved, the same kilowatt-hours of energy will be needed regardless of coordination. Systems under coordination therefore will operate at higher load factors and will make greater use of investment in generating plant.

The total energy requirement for the 48 power supply areas for 1980 is estimated to be 2,693 [3] billion kilowatt-hours (equivalent to 307 gigawatts at 100 percent load factor). With individual system peaks expected to total 502 gigawatts (noncoincident), the average load factor of the individual systems is estimated to be 61 percent for 1980. The estimated effect of various degrees of coordination on load factor is summarized as follows:

	Estimated coordinated peak loads for 1980 (gigawatts)	Estimated average load factor (percent)
Area coordination (which the industry is now approaching)	489	63
Sector coordination	477	64
Full coordination in the east	468	66
Nation-wide coordination	461	67

Utilization of Diversity

The Federal Power Commission is fully cognizant that the preliminary study of diversity savings reported herein is only an initial analysis of a complex determination. Limitations of data make long-run projections of diversity savings subject to considerable uncertainty. This is particularly true with regard to possible changes in the character of the load in the future. As the Power Requirements Advisory Committee Report No. 19, p. 286 of Part II, said, ". . . a substantial part of the large growth from 1970 to 1980 must be in segments of load which are not fully envisioned . . . if the number of new homes (19 million) forecast to be electrically heated materializes many of the load areas will trend to winter peaks in 1975 and 1980, especially in the north half of the United States."

Forecasting the growth in diversity is more uncertain than forecasting load growth. The magnitudes of diversity to be realized by 1980 may be smaller than the projections of this study but they may also be greater. As explained earlier, the time zone and random diversity components of the study were arbitrarily discounted to 50 percent of the calculated amounts. The three week-long periods in 1960 which formed the basis for the study may not have exposed the full amount of diversity within each of the 12 months of that year. In some areas diversity has been increasing at a faster rate than total load growth. On the other hand the efforts of individual electric utilities to improve their system load factors tend to retard the growth of diversity in relation to overall load expansion, although their general sales efforts may override this effect.

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[3] Excludes industrial in-plant generation, see table 14.

Summary and Conclusions

This preliminary analysis portends the opportunity by 1980 for reductions in capacity (allowing for scheduled maintenance) of as much as 30 million kilowatts (or about 6 percent) through full utilization of expected diversities. The industry is already utilizing, or planning to utilize, some of these diversity savings—the coming Tennessee Valley Authority—South Central Electric Cos. interchange of 1,500 megawatts of seasonal diversity is one example, and the American Electric Power Co. sale of 300 megawatts of summer capacity to enable the Commonwealth Edison Co. of Chicago to defer a generating unit in 1964 is another. However, if the substantial diversity savings that appear possible by 1980 are to be realized, more and larger steps must be taken toward industry-wide coordination.

Realization of the possible saving in overall cost requires an accurate determination of the magnitude of the diversities and in each case a careful evaluation of the cost of required transmission facilities in relation to the benefits. Diversity exchanges must be planned and contracts negotiated under which they can be scheduled since capacity reductions do not automatically occur merely because systems are interconnected.

The important points which our study clearly demonstrates are that (1) the savings that may be achieved through proper coordination and use of diversity are very large, (2) to achieve more definitive information much detailed load data must be assembled and analyzed by the industry with regard to diversity projections,[4] and (3) the economic inducements are such that all industry participants should seek to take early advantage of their diversity opportunities.

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[4] Steps have been taken by a Task Force on Power Capacity and Pooling organized by the Edison Electric Institute in 1963 to solicit the reporting of hourly load data on an industry-wide basis.

CHAPTER 14

REDUCTION IN RESERVES OF GENERATING CAPACITY

In order to maintain the uninterrupted service that customers expect and rely upon, all power systems must maintain or have access to more generating capacity than the expected annual peak load. This spare capacity, known as required reserves, changes from time to time and varies widely from system to system, depending on the system size, the sizes and types of generating units in the system, the forced outage rates for these units, maintenance requirements, and system load characteristics. In 1963, the installed margin of generating capacity of U.S. power systems averaged about 25 percent of the peak load requirements [1] of the individual systems.

In practice, total reserves are supplied in various ways, from units which are operating at less than full load and are available to meet immediate and sharp load increases, from hydroelectric and pumped storage units, gas turbines, diesels and similar types of capacity which can be started and placed on the line in a few minutes and from steam-electric units in cold reserve (operative but not in operation) or on low bank (idling at pressure and heat levels below that required for system service) which must be brought up to operating pressure and temperature over a period of several hours before being put on the line.

The discussion in this chapter is concerned with the extent of the need for reserves rather than the manner in which they may be provided. Here we are examining the factors which influence the magnitude of reserve capacity in order to determine in what way these requirements are affected by number and size of generating units in relation to system size and the extent by which reserves can be reduced through greater interconnection and coordination.

Kinds and Classes of Reserves

Reserves of generating capacity must be provided to meet three basic needs in order to assure the desired high-quality electric service, namely, (1) to replace generating capacity removed from service, upon little or no notice, because of failure or outage of generating equipment and in some cases because of loss of transmission facilities, (2) to replace generating capacity which is out of service for scheduled maintenance during the annual peak load season if all of this work cannot be accomplished in the off-peak season, and (3) to meet the contingency that loads will prove greater than those anticipated when commitments were made for new generating capacity.[2] Taken together, the need for these three classes, usually designated as reserves for unscheduled outages, reserves for scheduled outages, and reserves for uncertainties of load growth, respectively, determines the amount of generating capacity which must be provided in excess of the estimated loads. Factors relating to the magnitudes of these three components of reserve are discussed, in some detail, in the following sections.

Reserves for Unscheduled Outages

The amount of generating capacity required as reserves for unscheduled or forced outages [3] is dependent upon the assumed standard of system reliability, which is a function of the frequency and average time that each generating unit is expected to be out of service for unscheduled repair and the number and sizes of generating units in a system. If equipment must be taken out of service on shorter notice than one week, the outages are included in the unscheduled category.

Assumed Standard of System Reliability

It is a firm objective in system planning to schedule additions to system capacity which meet requirements for load growth and provide an acceptably high degree of reliability. The standard of service which underlies this study of reserve requirements conforms to the recommendation of the National Power Survey Advisory Committee[4] that sufficient reserve capacity be provided so that the use of all generating reserve margin would not be more frequent than once in five years, on the average. The margin is the difference between the capability of the installed units, plus any scheduled net power imports, and the peak load. The Committee's report indicated that because the outages of the capacity margin might occur at times when the load was below its peak level, loss of ability to serve a part of the load would be expected less frequently than a loss of reserve margin. In the example given by the Committee, a loss of margin once in five years corresponds to a "loss of load" probability averaging about once in ten to fifteen years.

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[1] Peak loads adjusted for seasonal power exchange within regions.

[2] For this category, a common practice in the industry is to include on a judgment basis an allowance for possible underestimation in the projected load demand.

[3] The proportion of time that a unit is expected to be out of service for unscheduled repairs, excluding the time for scheduled outage, is called the forced outage rate.

Forced Outage Rates

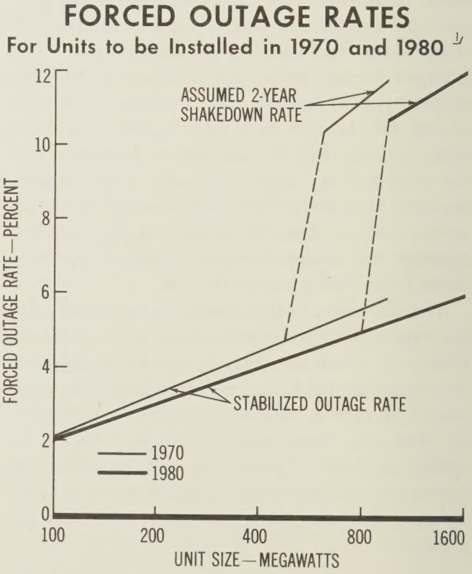
Data on the performance of generating equipment have been gathered by individual electric utilities for many years, assembled by the Edison Electric Institute, and analyzed in reports of the Institute of Electrical and Electronics Engineers. On the basis of such data, the National Power Survey Generating Stations Technical Advisory Committee prepared and included a schedule of forced outage rates in Advisory Committee Report No. 24.

The Committee indicated that the extra-large, high-temperature, high-pressure electric generating units of the future would most likely be shut down for unscheduled repairs more frequently than the much smaller generating units with lower temperatures and pressures built in the past, although the outage rate of large units "is expected to improve with time." In addition, the Committee suggests that double rates for forced outages be used for the first two years of operation of new large units until enough experience has been gained for a given size. With the rapid growth in unit sizes in recent years, the Committee believes that "there has been insufficient time to gain experience with new designs before they must be applied to other new and larger units." The higher outage rate projected for the first two years allows for correction of design deficiencies and for "shakedown" of the equipment. The designated future outage rates for 1970 and 1980 are shown graphically in Figure 104.

Thus, three principal trends are indicated in the report of the Committee, namely, increases in forced outage rates as the sizes of thermal electric generating units increase, higher outage rates for new larger units during the "shakedown" period, and gradual improvements in outage rates as advances are made in technology.

As an example of the anticipated technological improvement, a 400 megawatt boiler-turbine-generator unit installed in 1960 has a forced outage rate of 5.5 percent after the shakedown period, whereas a 400 megawatt unit installed in 1970 would be expected to have a 4.4 percent rate both during and after the shakedown period and the same size unit installed in 1980 would be expected to have a 4.0 percent forced outage rate.

Forced outage rates indicated for units of 1,000 megawatts or larger expected to be placed in serv-



1/ Based on Advisory Committee Report No. 24
Rates for Boiler-Turbine-Generator Units.

FIGURE 104 *As experience is gained, new designs bring about lower forced outage rates for units of a given size, but the outage rates, even for units which have completed their 2-year shakedown, are indicated to remain relatively high for the larger units.*

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[4] Advisory Committee Report No. 5, p. 35 of Part II.

ice in the 1970's are comparable to the 5.5 percent forced outage rate indicated for units in the 400 megawatt range placed in service in 1960 but not to the much lower rates, generally well below 2 percent, experienced in the 1940's and 1950's.

Outage rates for hydroelectric units will remain at a much lower level, the Committee predicted, only 0.5 percent for forced shut-downs.

Selection of Unit Sizes for this Study

This study is based on the assumption, that present trends toward stronger interconnections will be continued and that coordination among systems within each of the 16 coordination study areas will be accomplished by 1970. Similarly, it is assumed that coordination will be generally accomplished among the systems within each of the four study sectors during the 1970's and that interconnections will be extended to permit a high degree of nationwide coordination by 1980.

In this study a single pattern of unit sizes was selected for each period. The sizes selected are believed to be in keeping with the demonstrated economy of using large generating units and broadly expanded interconnections. The maximum unit size included in the study is 1,500 megawatts which conforms to the Advisory Committee's evaluation of the probable maximum economic unit size to be expected before 1980. The resulting size distribution of thermal generating units (fossil fuel and nuclear) anticipated for 1970 and 1980, as compared with those for 1950 and 1960 is depicted in figure 105, and the distribution of unit sizes assumed for 1980 is indicated in table 50.

TABLE 50

Number of Generating Units by Location and Size Group, Projected for 1980

Coordination study sector	Thermal generating units								
	0–99 mw.	100–199 mw.	200–399 mw.	400–599 mw.	600–799 mw.	800–999 mw.	1,000 mw.	1,200 mw.	1,500 mw.
Northeast	939	166	71	13	18	16	29	12	10
North Central	1214	67	28	9	14	7	9	4	8
South	1248	161	76	10	20	25	27	13	5
West	217	56	29	4	2	8	11	4	5
Total U.S.[1]	3618	450	204	36	54	56	76	33	28

	Hydroelectric generating units [2]			
	0–9 mw.	10–49 mw.	50–99 mw.	100–over mw.
Northeast	434	229	186	25
North Central	71	133	12	22
South	143	572	48	0
West	305	382	243	118
Total U.S.[1]	953	1316	489	165

[1] Excluding Alaska and Hawaii.

[2] Including pumped storage.

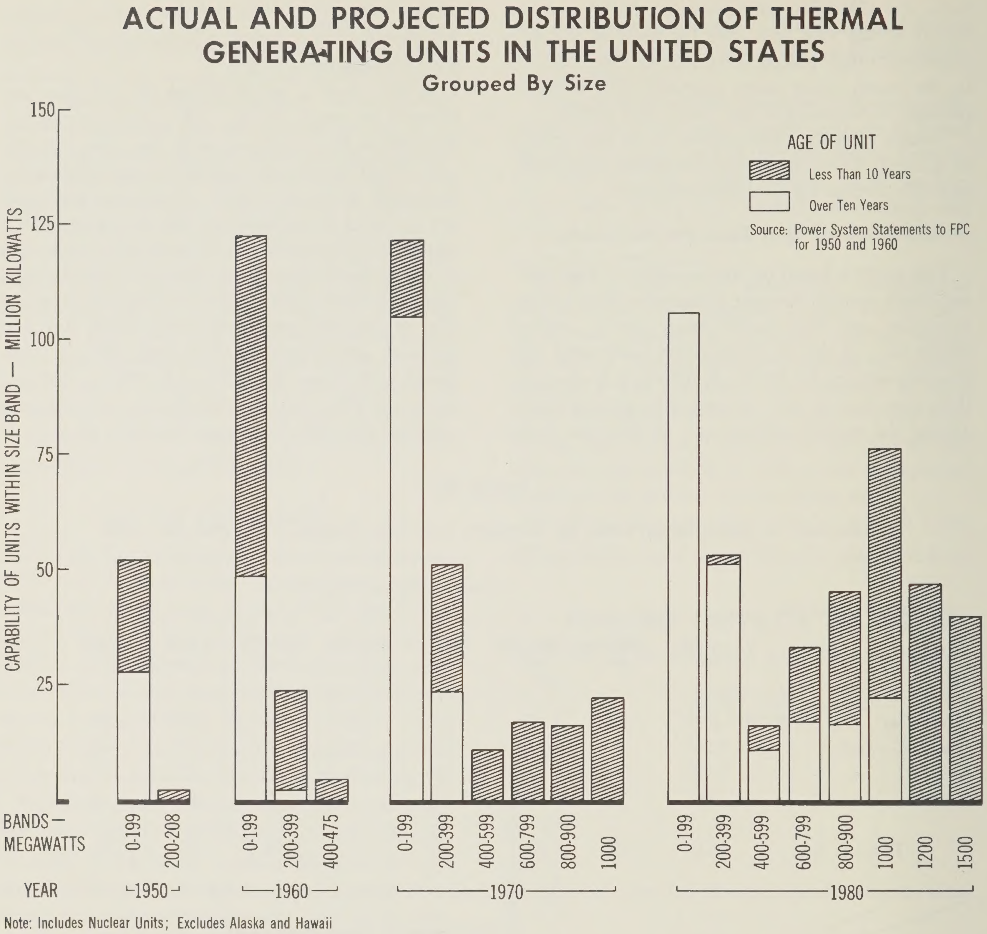


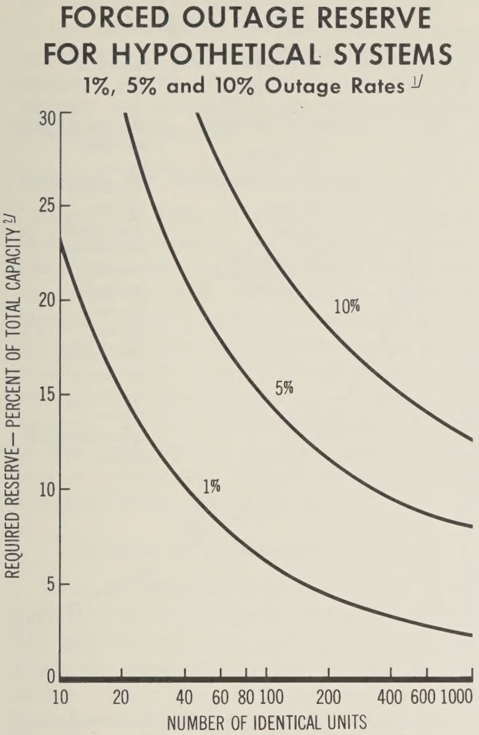
FIGURE 105 *The projected trend continues toward larger, more economical generating units, with half of the capacity indicated for 1980 in units of 600 megawatt or larger.*

Obviously detailed analyses of various combinations of unit sizes and of progressive patterns of coordination will be made by individual systems and groups in the process of planning coordinated ventures. Further comments on unit sizes of generating stations are contained in Chapter 15, Part A.

Effect on Reserve Requirements of Number and Size of Units and Size of Systems

A larger reserve for unscheduled outages is required if capacity is concentrated in large units rather than in smaller but more numerous units. However, as the size of the operating systems expands through load growth and through extension of coordination to include more systems, the size of any given unit or combination of units in relation to the total capacity becomes less, and the proportion of capacity required for reserve is reduced.

Figure 106 illustrates the reserve requirements for hypothetical systems composed of identical units and permits a ready observation of the downward



1/ Average Duration of Five Days, Average Frequencies Are Once in 500, 100, or 50 Days, Giving Forced Outage Rates of 1%, 5% and 10%.

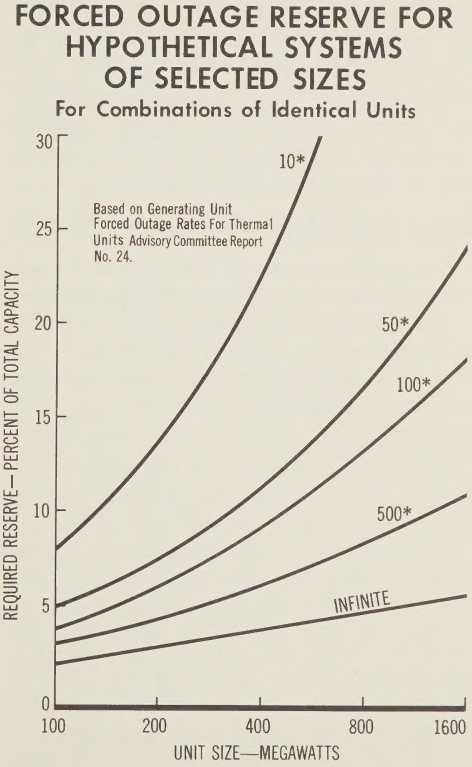
2/ For Loss of Margin Less Than Once in 5 Years on The Average.

FIGURE 106 *The portion of capacity required for reserve generally decreases as the system grows. This is illustrated above for groups composed of ten or more identical units.*

trend in reserves which comes with expanding system size. As shown by the bottom curve, if each unit has a forced outage rate of one percent and the number of units in the coordinated power pool increases from 20 to 100, reserve requirements for unscheduled outages drop from 15 percent to 6 percent. Thus, five systems operating separately with 20 generating units in each system would have a total of one hundred identical units, fifteen of which would be required for reserve. If the systems should form a pool, only six units would be required for reserve, and the saving in capacity requirements would equal nine generating units.

The opposing effects on reserves of larger units and larger systems can be generally appraised by observing the trends illustrated in figure 107 which again uses hypothetical systems. Figure 107 was prepared utilizing forced outage rates corresponding to the bottom curve of figure 104 which reflects the technological improvements expected by 1980 and assumes the units have passed through the shakedown period.

In general, a system normally grows to meet increases in load, but growth in "connected load" may be accelerated very rapidly by interties between systems to facilitate the sharing of reserves and the planning for new capacity. In this way, a system can take advantage of increased unit size without adverse impact upon reserve requirements and at the same time secure the benefit of the greater ef-



* System Size in Gigawatts (1,000 Megawatts)

FIGURE 107 *Reserve requirements will be higher if larger units are chosen as an alternative for smaller units, but the difference becomes less as the size of the system (the coordinated systems) increases.*

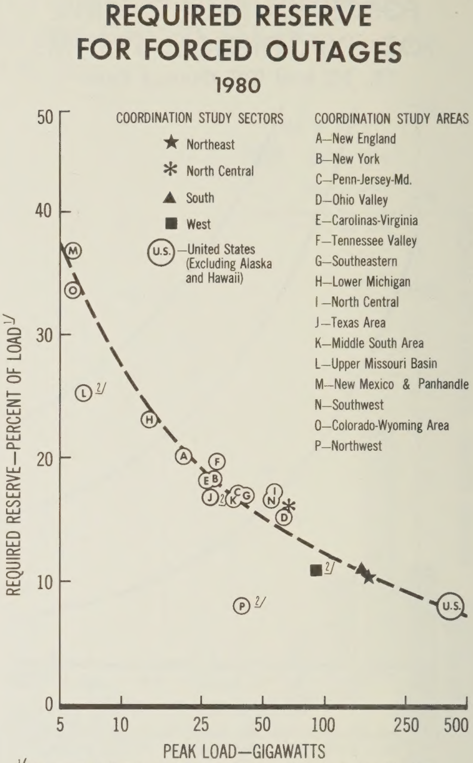
ficiency and lower capital and operating costs of the larger units.

The curve for a 500,000 megawatt (500 gigawatt) system, Figure 107, represents a combination of interconnected systems approximately large enough to serve the entire United States (excluding Alaska and Hawaii) in 1980. If this amount of capacity should operate in a single coordinated pool by 1980, it would represent an increase of 30 to 50 times over any fully coordinated group of systems today.

Extensive increases in coordination over any present systems will mean that a generating unit considered very large in relation to electric systems of today will be much smaller in relation to the probable size of systems of a decade from now. Even if these larger units prove to have higher forced outage rates than smaller units, the resulting increase in reserves can be outweighed by the economic advantages of very large units. The overall reserve for forced outages may remain constant or even decrease with the more extended coordination depending on the timing of installations of the very large generating units.

Forced Outage Reserve Requirements for 1980

The required reserves for forced outage for each of the 16 study areas, the four sectors, the two zones and for nationwide coordination were determined from involved probability studies relating to the "loss of capacity margin" and utilizing the single mix of unit sizes selected for the survey study. The "loss of capacity" method of determining reserve requirements applies data and computations consistently both to systems and groups of systems, allowing a comparative analysis to be made.



[1] For Generating Units Assumed for 1980 and Loss of Margin No More Than Once in Five Years on the Average.

[2] Reflects Influence of Substantial Hydroelectric Capacity.

FIGURE 108 *With nationwide coordination in 1980, estimated reserves for forced outages required in each system would average about 8 percent of the load. Separately coordinated areas, utilizing the same selection of units, would require higher reserves as indicated.*

The results of the forced outage study are presented in figure 108. The calculations are based upon the forced outage rates anticipated for each unit assumed to be in service in 1980, taking into account unit age and reduction in exposure to forced outages for the period that each unit is on scheduled outage. The percentage requirements are higher for areas with smaller loads such as L, M, and O and are lower for the areas with larger loads particularly where large amounts of hydroelectric capacity are included, notably in area P. If the "once-in-five-year" criterion is applied to the nation as a whole, the required reserve for forced outages is computed as 37 gigawatt for 1980. This amounts to approximately 8 percent of the coincident peak load.

As discussed in Chapter 4, the trends in forced outage rates for large generating units are uncertain because of lack of extensive operating experience with such units. If outage rates do not rise to the levels forecast by the Advisory Committee, 1980 reserve requirements will be somewhat lower. If, for example, the outage rates should prove to be 25 percent less than the assumed values, the reserves required for forced outages in a nationwide pool would drop from 37 to 30 gigawatt—7 million kilowatt of capacity. On the other hand, if outage rates should be greater than predicted, the reserve requirements will increase. The difference—upwards of a billion dollars in investment—is large enough to provide a strong incentive for continued research and development to improve reliability of large generating units.

Reserves for Scheduled Outages

Generating units are taken out of service at fairly regular intervals for inspection, overhaul, and repair as required. This practice accounts for the relatively high reliability of generating capacity. When conditions are such on an electric system that generating capacity needed to supply load must be taken out of service, generating capacity from reserves must be provided to take its place. The amount of reserves needed at time of peak load depends on the duration of maintenance outages and whether the work can be scheduled during offpeak months.

Duration of Maintenance Outages

There are variations from year to year in the amount of scheduled maintenance that a generating unit requires, and some types of inspection and repair are needed only at two or three year intervals. There are also variations in intervals between scheduled outages and in downtime for maintenance because of such factors as age, size and type of unit. On the average, baseload boiler-turbine-generator units require about one month of scheduled maintenance per year.[5]

In general, the relatively large generating units will be operated at higher use factors and will require more time for maintenance than the smaller units. For purpose of analysis of 1980 reserve for scheduled outages, the large size thermal units, 600 megawatt or over, were assumed to require 600 hours of scheduled maintenance annually, while units of 200 megawatt to 599 megawatt size were assumed to require 500 hours, and units under 200 megawatt, 400 hours. For pumped storage units and conventional hydroelectric units, an average of about 150 hours per year was assumed. However, for conventional hydroelectric units, the maintenance can often be scheduled in relation to water availability so that the units remaining in service can at all times equal the performance obtainable from all units under adverse flow conditions. Accordingly, it was assumed that no scheduled maintenance time need be considered for conventional hydroelectric units if adverse flow conditions are used to determine the dependable machine capabilities.

Scheduling of Maintenance

In estimating the amount of reserve required for scheduled maintenance, it is necessary to determine whether there is enough time and spare capacity to take all units out of service for their scheduled overhaul during off-peak months. In actual practice, such a determination would involve extensive calculation if there were many units in the system and the scheduling were tight. Various combinations would be explored to determine the optimum schedule in terms of utilizing the spare capacity available in generating units of different sizes for each interval. At the same time the maintenance schedule should provide for reasonable use of the crews and not result in excessive loading on parts of the transmission system. For purposes of this study, however, an estimate of the reserve required for scheduled maintenance was made from a comparison of the total time available for work during seasons of reduced load, calculated in gigawatt-months,[6] with the total required maintenance work, also calculated in gigawatt-months. This work-time requirement was increased by 15 percent to provide some leeway in detailed scheduling.

The generating capability of a system may change month by month because of retirements, additions, cooling water limitations, and seasonal changes in the output capability of installed hydroelectric units. A time schedule for the installation of new generating units was assumed which would be sufficient to cover retirements and meet the increments in load as they occur. Variations in hydroelectric capability were accounted for by subtracting from the load plus the reserve allowance for forced outages, the capability of the hydroelectric units for the given month under adverse flow conditions. The remainder is the "net thermal capacity" required.

Comparison of Scheduled Maintenance Requirements

In table 51, the unused capacity (in gigawatt-months) considered to be available during 1980 is listed in Part 1 for each of the 16 coordination study areas. In computing the capacity estimated to be available for maintenance in 1980, the net thermal capacity in each area was compared each month with net thermal capacity required. The aggregate capacity available, in gigawatt-months, is shown in the first column of the table. For seven of the areas, the aggregate capacity available was equal to or more than the maintenance requirements, so that in these areas no reserve would be required for scheduled on-peak maintenance. To cover the maintenance requirements in the remaining coordination study areas, it was assumed that the additional required reserve capacity, shown on the bottom line of the table, would be added at the beginning of the year.

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[5] Advisory Committee Report No. 24, p. 405 of Part II.

[6] Millions of kilowatt-months.

The reserves for scheduled outages for system coordination based on the eight regions, the four sectors, the three eastern sectors combined, and all systems together are presented in Part 2 of table 51. The progressive formation of larger coordinated groups results in a decrease in the total amount of capacity required for serving load due to diversity in peak loads, which apparently is offset in part by an increase in reserve for scheduled maintenance because seasonal exchanges within the in-

TABLE 51

Estimate of Reserves for Scheduled Maintenance Required in 1980

Part 1—Assuming Study Area Level of Coordination

Coordination study area	Estimated available off-peak capacity [1] (GW-months) [2]	Estimated scheduled maintenance (GW-months) [2]	Unassigned excess (GW-months) [2]	Additional requirements (GW-months) [2]
A—New England	11	14	0	3
B—New York	11	20	0	9
C—Pa.-N.J.-Md	19	34	0	15
D—Ohio Valley	13	50	0	37
E—Carolinas-Virginia	10	19	0	9
F—Tennessee Valley	55	20	35	0
G—Southeastern	24	33	0	9
H—Lower Michigan	5	11	0	6
I—North Central	39	51	0	12
J—Texas Area	65	16	49	0
K—Middle South Area	68	27	41	0
L—Upper Missouri Basin	8	4	4	0
M—N. Mex. & Panhandle	9	5	3	0
N—Southwest	21	39	0	18
O—Colo.-Wyo. Area	4	4	0	0
P—Northwest	39	6	33	0
Total	401	354	165	118

Required reserve—11 gigawatts [3]

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[1] Assumes monthly variations in reserves for forced outages and uncertainty in the short-range forecast would be negligible.

[2] Gigawatt-months (millions of kilowatt-months).

[3] One-twelfth of additional maintenance requirements expressed in gigawatt-months, plus 13% as an allowance for outage time of the additional capacity.

NOTE.—Sum of individual items does not always equal total because of rounding.

TABLE 51

Estimate of Reserves for Scheduled Maintenance Required in 1980

Part 2—Assuming Regional, Sector, and Nationwide Levels of Coordination

Coordination within regions	Estimated available off-peak capacity [1] (GW-months) [2]	Estimated scheduled maintenance (GW-months) [2]	Unassigned excess (GW-months) [2]	Additional requirements (GW-months) [2]
I—Northeast	40	68	0	28
II—East central	17	62	0	45
III—Southeast	73	73	0	0
IV—North central	39	51	0	12
V—South central	142	48	94	0
VI—West central	12	9	3	0
VII—Northwest	39	6	33	0
VIII—Southwest	21	39	0	18
Total	381	354	130	103
Required reserve—10 gigawatts. [3]				
Coordination within sectors				
Northeast	60	130	0	70
North central	49	60	0	11
South	132	120	12	0
West	46	45	1	0
Total	287	354	13	81
Required reserve—8 gigawatts. [3]				
Coordination within east and west zones				
East	200	310	0	109
West	46	45	1	0
Total	246	354	1	109
Required reserve—10 gigawatts. [3]				
Nationwide coordination				
Total	203	354	0	152
Required reserve—14 gigawatts. [3]				

Footnotes.—See part 1 of Table 51.

terconnected group tend to reduce opportunities for scheduled maintenance during off-peak months. In some cases, however, grouping results in surplus off-peak capacity in one area being available to meet reserve requirements in another, thus leading to a reduction in total reserves for scheduled maintenance. These opposing effects account for a decrease in required reserve for scheduled maintenance as the extent of coordination progresses from 16 areas to 4 sectors, but an increase in the required reserves for maintenance is indicated as coordination is further extended.

To secure the possible reserve reduction referred to, areas with no surplus offpeak capacity which receive power from the surplus offpeak capacity of other areas would "double up" their maintenance work when power imports were available, and defer maintenance at other times, then using all available capacity to export power to meet the peak loads in other areas.

Reserves for Uncertainties of Load Growth

There is an element of uncertainty in planning the amount of generating equipment which should be added each year to meet expected load growth. The uncertainty lies in the unforeseen increases in load which may develop in the three to four years that it takes for the construction and installation of major additions to generating capacity. From past records for a given system or combination of systems, it is possible to determine the deviations from previous forecasts, estimate the probability that future forecasts will be exceeded, and thus calculate the reserve necessary to protect against such a contingency.

Reports submitted monthly to the Federal Power Commission on Form 12–E[7] by reporting groups, which account for about 97 percent of the electric energy supplied by all utilities, contain a series of forecasts which may be compared with the actual peak loads which later occurred. Such comparisons have been made of successive forecasts, reported each January, of the peak loads for that year and the succeeding three years (the "one-year", "two-year", "three-year" and four-year" forecasts) with actual loads subsequently experienced. Composite forecasts were obtained by adding together the forecasts of individual systems, and they were compared with composite peak loads similarly determined by adding together the individual system peak loads. The results were plotted on ten curves which are shown in figure 109. These curves represent a four-year series of composite forecasts of non-coincident system peaks for all systems submitting Form 12-E reports, as compared with the peak loads actually experienced for the ten years 1954–1963, inclusive.

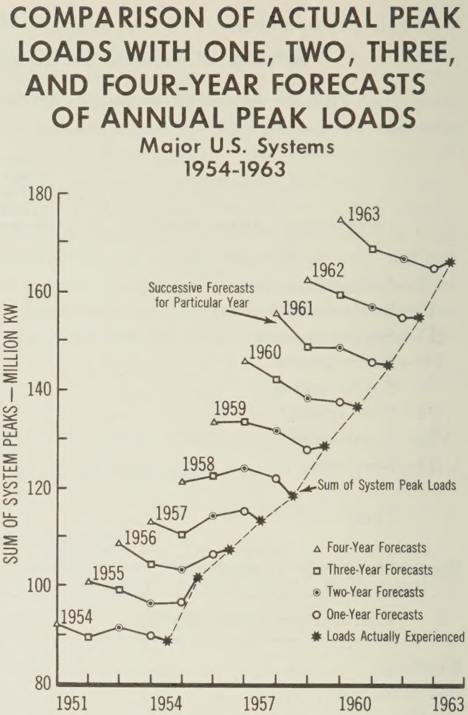

FIGURE 109 *The intervals between forecasts and occurrence of the load are shown by symbols. The date assigned to a series of forecasts is the year in which the load was experienced. For the 1954 peak load, four-year forecast was reported in January 1951, three-year forecast in January 1952, two-year forecast in January 1953, and one-year forecast in January 1954. For the loads occurring from 1955 to 1958, the four-year forecasts proved to be the most accurate.*

The composite forecasts and actual loads were systematically compared for each year, 1954 to 1963. The average percentage deviation of the type of forecast in question[8] over the ten-year period was then subtracted from each yearly percentage deviation in order to eliminate any high or low bias. The resulting percentage deviations from the average were taken as representative of the difference between future forecasts and actual loads. The values are arranged in descending order in the second column of table 52. The probabilities of loss of reserve shown in the last column of the table result from multiple outages equal to or in excess of the margin between installed capacity and peak load. The first line on table 52 shows, for example, that the chance that an outage of 35 gigawatts will occur at the same time that a peak load of 479 gigawatts is experienced, is, on the average, only 70 in a million. The total of the last column is 83 which corresponds, in this case, to a loss of reserve margin of only once in 5 years. In calculating the reserve for uncertainties of load growth, the amount of installed capacity was adjusted until the overall probability of the simultaneous occurrence of high loads and outages of capacity became equivalent to this "once-in-five-years" loss of margin.

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[7] Monthly Supplement to Power System Statement.

[8] For example, the average deviation was 3.62 percent of the actual load for the forecasts made four years in advance.

Of the total 52.7 gigawatts reserve for forced outages and for uncertainties of load growth used in table 52 as the necessary "once-in-five-years" reserve for 1980, 37 gigawatts [9] as previously derived may be considered as the reserve for forced outages. The 1980 reserve requirement for "uncertainties of load growth" (assuming virtually full countrywide coordination) is 15.3 gigawatt calculated on the basis of the deviations of the four-year forecasts from actual. The four-year forecast was selected as the appropriate basis for computing the reserve for load growth uncertainties because it represents the usual time needed for planning and construction of generating capacity. Similar reserves for one-year, two-year and three-year forecasts are as follows:

One-year forecast.	10. 5 gw.
Two-year forecast	15. 2 gw.
Three-year forecast.	11. 1 gw.

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[9] 37.4 gw. to be exact.

TABLE 52

Effect of Deviations in Load Forecasts Upon Reserve Margin

Load forecast [1] (GW [2])	Assumed percentage deviation of actual load from forecast [3]	Resulting load (GW [2])	Assumed capacity [4] (GW [2])	Excess of capacity over load (GW [2])	Probability of loss of reserve margin (parts per million) [5]
(1)	(2)	(3)	(4)	(5)	(6)
461	+3. 96	479	514	35	70
461	+3. 46	477	514	37	13
461	+1. 51	468	514	46	0
461	+1. 49	468	514	46	0
461	+0. 78	464	514	50	0
461	+0. 38	463	514	51	0
461	—1. 97	452	514	62	0
461	—2. 15	451	514	63	0
461	—3. 75	444	514	70	0
461	—4. 43	441	514	73	0

[1] Anticipated coincident peak load for U.S.—1980 (adjusted for diversity, Table 49).

[2] Gigawatts—millions of kilowatts.

[3] Each deviation is the percent variation of the 4-year forecast from the peak load for one of the years, 1954 to 1963, less 3.62% which is the average deviation for the period.

[4] Equivalent to load forecast, plus a forced outage reserve of 37.4 gw and a reserve for forecast uncertainty of 15.3 gw for a total margin of 52.7 gw (see text).

[5] Applying a probability factor of 0.1 to represent the probable "occurrence of load", see text. Last eight lines show the chance of losing the full amount of excess capacity given in column (5), at the time the peak load shown in column (3) is experienced, is less than one in a million.

Reserve requirements for uncertainties of load growth are sensitive to the size of territory and number of systems included in the composite forecast. Moreover, the deviation of a composite forecast reflects the modifying effect of the independent estimates of the various systems in the composite, each analyzing its own area loads and viewing the future from its own vantage point. Diversity in type of loads within a wide composite area also improves the probable accuracy of the composite forecast by making the total less sensitive to variations in temperature and rainfall, unexpected changes in industrial output, and other factors which influence some loads more than others. In a coordinated power pool the reserves for uncertainties of load growth are thus reduced by the partly offsetting nature of local forecast errors, due both to the multiplicity of types of loads and the diversity realized in local forecasting and planning.

The estimated 1980 reserve for load growth uncertainties required under coordination by sector or among the three eastern sectors would be somewhat higher than for full nationwide coordination. The comparison is as follows:

Sixteen study areas	22 gw.
Four individual sectors	17 gw.
Eastern zone	17 gw.
Countrywide coordination	15 gw.

Summary and Conclusions

To serve the loads estimated for 1980, under the assumptions used in the Survey as to types of power supply, unit sizes, forced outage rates, and maintenance requirements, the total capacity needed, including that for uncertainties of load growth, is estimated to be in the order of 527 gigawatts.[10] This assumes that full sharing of generating capacity on a nationwide scale proves economically justifiable by that date.

The categories of reserve capacity included in the 527 gigawatts are itemized in table 53. The table also summarizes for the 16 coordination study areas, the four sectors, two zones, and the systems as one group, the net peak capacity requirements (after diversity exchanges are accounted for as explained in Chapter 13) and similar amounts of required reserve capacities. To assist in observing the trends in reserve requirements as the systems are arranged in larger groups, the estimates of reserve capacity are also given as a percentage of the peak load requirements. The effect of group size is particularly pronounced on reserve capacity required for "forced outages". For the mix of unit sizes assumed, the forced outage requirements varies from an average of 17.0 percent for the 16 study areas to 8.1 percent for full nationwide coordination.

The estimates of 1980 diversities and reserve requirements for various groups of systems are, of course, subject to considerable variations. For example, it is difficult to determine this far in advance the forced outage rate on the large generating units assumed for 1980. If the forced outage rate is less than indicated, the advantage of tying the east and west zones together will be reduced, and if higher, the advantage will be increased. Nevertheless, it demonstrates the relative benefits of more extensive coordination.

The reserve required of about 15 percent, indicated as needed for full coordination in table 53, is 10 percent less than the average margin of capacity above peak loads experienced by U.S. power systems in 1963. Examination of reserve margins for five years prior to 1963 discloses percentages of margin of similar magnitude, varying from 23 to 28 percent. The 1963 margins include power available to systems through planned seasonal diversity exchanges but apparently not through interchanges arranged between systems on short notice.

The savings in reserve capacity reduction resulting from proceeding from the 1963 level of system coordination to full coordination by 1980 has been taken as ten percent of the 1980 peak load. In round figures this amounts to 50 gigawatts of capacity—a saving of over $5 billion in generating plant as a result of coordination on a national scale, offset by the cost of the increased transmission requirements.

The reduction in reserve requirements, under coordinated operation, would be accomplished by making capacity available for transfer through adequate interconnections. Some of the savings in reserves under coordinated operations can be obtained by constructing 230 kilovolt lines, others can be obtained only by building 345, 500, or 700 kilovolt lines. The status and opportunities for co-

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[10] Millions of kilowatts.

TABLE 53

Estimate of Required Reserve Capacity and of Total Power Supply Needed for Areas, Sectors and Zones Through Full Nationwide Coordination in 1980

	Total power supply needed for load plus reserves assuming full coordination in			
	16 Study areas	4 Sectors	2 Zones	Entire U.S.[1]
Peak Loads—Gigawatts [2]	489	477	468	461
Reserves—Gigawatts:				
On-peak maintenance	11	8	10	14
Forced outages	[3] 83	[3] 55	[3] 43	37
Load growth uncertainties	22	17	17	15
Total reserves	116	80	70	66
Total of loads plus reserves	605	557	538	527
Reserve power requirements as a percentage of load:				
On-peak maintenance	2. 2	1. 7	2. 1	3. 0
Forced outages	[3] 17. 0	[3] 11. 5	[3] 9. 2	8. 1
Load growth uncertainties	4. 6	3. 6	3. 7	[4] 3. 3
Total	23. 8	16. 8	15. 0	[4] 14. 4

[1] Excludes Alaska and Hawaii.

[2] Millions of kilowatts.

[3] Sizes of generating units based on nationwide coordination. Forced outage requirements computed on the assumption of transfer of reserves among study areas, sectors and zones.

[4] A more common industry practice is to include the allowance for load growth uncertainties as part of the load. Thus the calculated reserve in terms of customary industry practice is about 11% of the load.

ordination are discussed by separate areas and sectors in chapter 15, and the overall economic evaluation is given in chapter 17.

It is likely that forced outage rates will be lower than forecast and consequently the total requirement for reserve generating capacity in percent of total load requirements would be less than the 14.4 percent shown on the bottom line in table 53. Nevertheless, these figures give some indication of the order of magnitude of reductions in reserve requirements that could be achieved by immediately expanding interconnection among present systems.

CHAPTER 15

PATTERNS OF GENERATION AND TRANSMISSION FOR 1980

PART A—PLANNING CRITERIA

The tremendous growth of the electric power industry in the decades ahead presents an opportunity for the industry to perfect expansion plans that will utilize the most efficient facilities available and that will coordinate the operations of individual power systems so as to bring the greatest benefits to electric consumers and the industry.

We are of course aware that few if any elements in the structure and operation of electric power systems remain constant and that even small changes in the relative cost of fuel, transportation, generation by various alternatives, or other elements of various system expansion alternatives could greatly alter the mix of the kind of generation and transmission plant which will be built in the future. Hence, it is not possible to predict with assurance the patterns of generation and transmission that can be expected to serve the projected loads of 1980.

The patterns presented in the following pages therefore are in no sense a program or a blueprint, but they may be helpful to many—especially to persons not intimately involved in power supply planning for a large area—in identifying the ways in which the cost of electric system operations can be reduced and in indicating the high order of magnitude of some of the many achievable gains.

The value of making a projection of one possible pattern of development which the Commission has undertaken in the survey lies not so much in the numbers determined or the particular configuration selected as in the examination of the concepts and possibilities, as well as apparent trends, which lead to these determinations. The National Power Survey's general patterns of development hopefully will encourage the industry to make the more detailed plans which will modify and refine our suggestions and lead ultimately to the design and construction of power facilities that will operate at the lowest possible cost to the nation. Adjustments in the outlook will be needed from time to time but the breadth and magnitude of potential improvements are expected to remain abundant.

Successive Enlargement of Areas of Coordination

A key element in the industry's planning for the future is the progressive enlargement of geographical areas of coordination. This basic concept is essential to the realization of the full economic advancement of our modern technology in electric power facilities. Coordination involves the construction of heavy interties with sufficient capacity to enable virtually complete sharing of reserves and diversities and other advantages within the geographical area in question. It also involves a high degree of planning and construction of new generating and backbone transmission facilities and cooperation in dispatching of loads among all segments of the industry present in the area, large and small. The Commission believes that such coordination can be accomplished without altering existing patterns of ownership and also without undue centralization of the dispatching and planning functions. To make this goal a reality will require a cooperative effort in which the managers of each system throughout the nation will put aside past differences and habits of isolation and concentrate their efforts on the mutual benefits of equitably sharing in a truly integrated system of power supply for the entire country.

The history of the industry, especially in recent years, gives promise that the degree of coordination we envision can and will be achieved.

Generally speaking, great progress toward coordinated operation already has been accomplished among the principal systems within the 48 areas which the FPC designated as power supply areas. Interconnections between larger systems have been extended beyond the 48 power supply area boundaries in some locations. However, there are many systems, particularly the smaller ones, which have not as yet achieved the major benefits of coordination even within these areas.

A number of power pools in which many systems are coordinated are operating within the 16 larger "coordination study areas", and in several instances, reserves and diversities are being shared across the boundaries of regions and even broad sectors of the country. In many interconnected situations, however, the depth of coordinated system planning has not progressed to the point of taking full advantage of joint planning of generating capacity. Many systems are still installing relatively small and inefficient generating units.

The survey analysis justifies the conclusion that it would be economical and practicable for all utilities to effect interconnection and coordination within each of the 16 study areas (lettered A to P) by 1970, with full coordination within each of the four sectors (figure 110) to be well on its way by that time, and completed by the mid 1970's. All segments of the industry are urged to pursue detailed coordination studies to assure that this goal is reached as soon as it can be proved economically beneficial. The boundary limits are in many cases arbitrary, and are not intended as limitations on planning.

By 1980, it is expected that virtually full coordination will be completed both east of the Rockies and west, and that substantial interconnections between the east and west zones will be established. Detailed planning studies to investigate further the economics of intersector transmission ties should be undertaken promptly by cooperating industry groups.

Geographic Distribution of Electric Loads

The distribution of loads as depicted in figure 111 clearly portrays the wide variation in load density. More than 90 percent of the total load is concentrated within areas largely east of the Mississippi River and on the west coast which comprise only 40 percent of total area of the United States.[1] The remaining 60 percent of the country has less than 10 percent of the load. A large area of light load density, roughly 1,000 miles in width,

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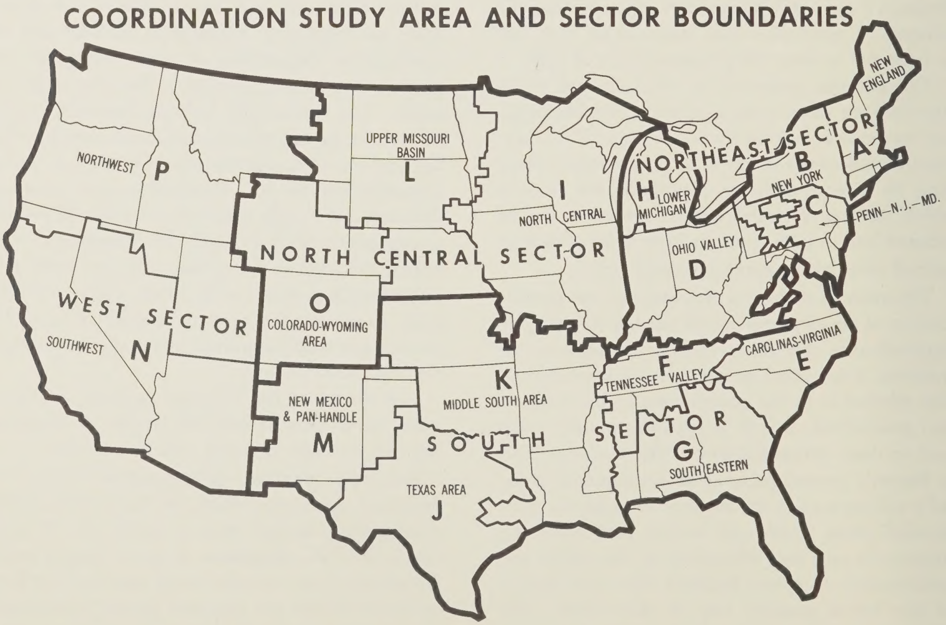
[1] Shaded areas on the map account for 94 percent of the country's load.


COORDINATION STUDY AREA AND SECTOR BOUNDARIES
NEW ENGLAND
A
NORTHEAST SECTOR
B
NEW YORK
C
PENN—N.J.—MD.
NORTHWEST
P
UPPER MISSOURI BASIN
L
I
NORTH CENTRAL
H
LOWER MICHIGAN
NORTH CENTRAL SECTOR
OHIO VALLEY
D
WEST SECTOR
O
COLORADO-WYOMING AREA
SOUTHWEST
N
K
MIDDLE SOUTH AREA
F
TENNESSEE VALLEY
CAROLINAS-VIRGINIA
E
NEW MEXICO & PAN-HANDLE
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SOUTH SECTOR
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TEXAS AREA
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Figure 110

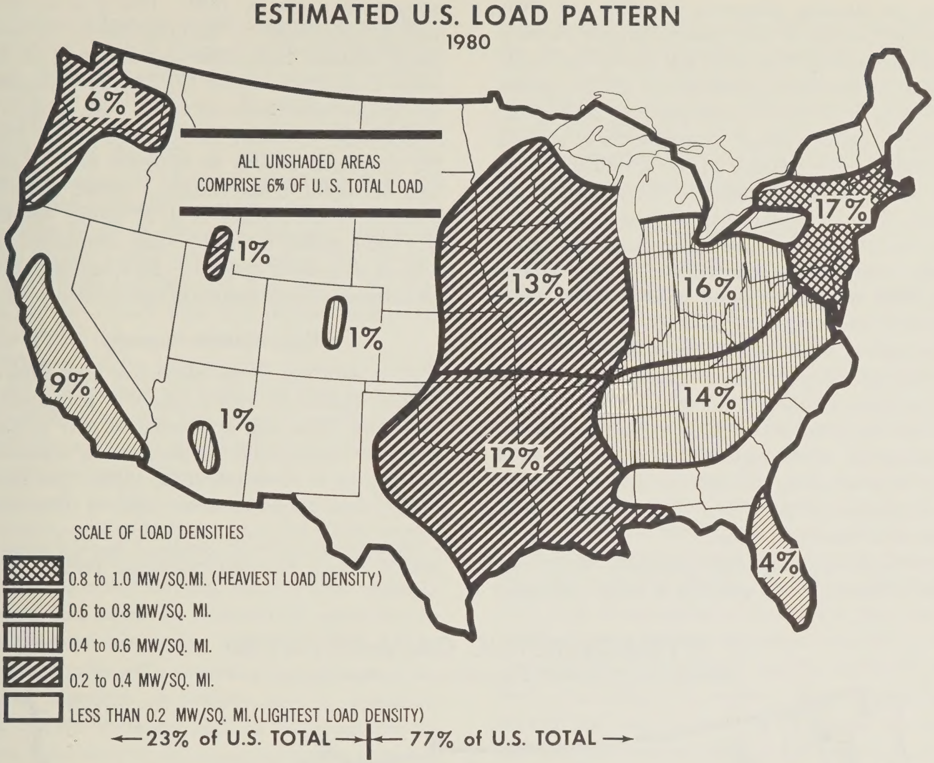
ESTIMATED U.S. LOAD PATTERN
1980
6%
ALL UNSHADED AREAS COMPRISE 6% OF U. S. TOTAL LOAD
1%
1%
13%
16%
17%
9%
1%
14%
12%
4%
SCALE OF LOAD DENSITIES
0.8 to 1.0 MW/SQ.MI. (HEAVIEST LOAD DENSITY)
0.6 to 0.8 MW/SQ. MI.
0.4 to 0.6 MW/SQ. MI.
0.2 to 0.4 MW/SQ. MI.
LESS THAN 0.2 MW/SQ. MI. (LIGHTEST LOAD DENSITY)
←23% of U.S. TOTAL→ ←77% of U.S. TOTAL→

Figure 111

separates the more heavily loaded eastern and western sectors. Concentration of major load areas occurs near the coasts and on principal inland waterways. High load density and the contiguity of important major load areas in most sections of the nation are highly favorable factors in the ease and economy of inter-system coordination.

Most of the generating capacity which will be supplying the projected loads of 1980 is yet to be placed in operation. The required increase in generating capacity for load and reserves is estimated to be in excess of 300 gigawatts.[2] To this must be added replacement of some present equipment which will be retired in the intervening period, estimated to be 30 to 50 gigawatts. The total addition of nearly 350 gigawatts is more than 1½ times the total generating capacity now in service, some 200 gigawatts, and about 67 percent of the estimated capacity of 527 gigawatts which will be required to supply the 1980 demands. About 50 gigawatts of this amount—representing capacity additions needed by 1966—is already in the construction stage. Thus from 1967 to 1980, the nation's electric power systems will be adding some 300 gigawatts of capacity—in effect a new electric power industry 1½ times as large as the existing one.

The Selection of New Capacity

The economic selection of potential new generation resources for purposes of this study has been greatly aided by the studies of Regional Advisory Committees composed of members from all segments of the electric utility industry. Their duties, while advisory to each of the five regional offices of the Federal Power Commission with which they were associated, resulted in substantial contributions to planning programs for 1970 and 1980. General patterns in both generation and transmission evolved from their work and efforts were made within the limited time available to effect a reasonable degree of coordinated planning among the various regional groups. Although many changes and additions were made by the Washington staff, the studies were very helpful. They were an excellent base for examination of benefits from further coordination and associated large scale planning. Hopefully these regional study groups constitute the beginning of more comprehensive efforts in joint planning to make the patterns of development which the survey envisions a reality.

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[2] A gigawatt is one million kilowatts.

The selection of the type, location, size and in-service dates of new capacity to meet the future requirements of the electric industry was made by an examination of the requirements and resources of each area including the opportunity for inter-area participation in large joint undertakings and in some cases imports of capacity.

It was assumed that large generating units in sizes up to 1,500 megawatts would be in service and operating satisfactorily by 1980. This is in harmony with the projections for maximum size by the Generating Stations Committee and contained in Advisory Committee Report No. 7.[3] The coordination studies were optimized on the basis of national coordination in making use of large units. Time did not permit making an optimum study of each area or region of the country. Before definitive conclusions are reached it is, of course, essential that such studies be made, using alternative patterns of unit size to determine the optimum pattern for progressive enlargement of coordinated areas.

Hydroelectric Capacity

As an early step in the selection of generation resources, summaries were prepared of potential hydroelectric capacities at existing or new projects which are economically feasible and may reasonably be expected to be completed by 1980. (See figure 112.) Such additions from 1967 to 1980 total

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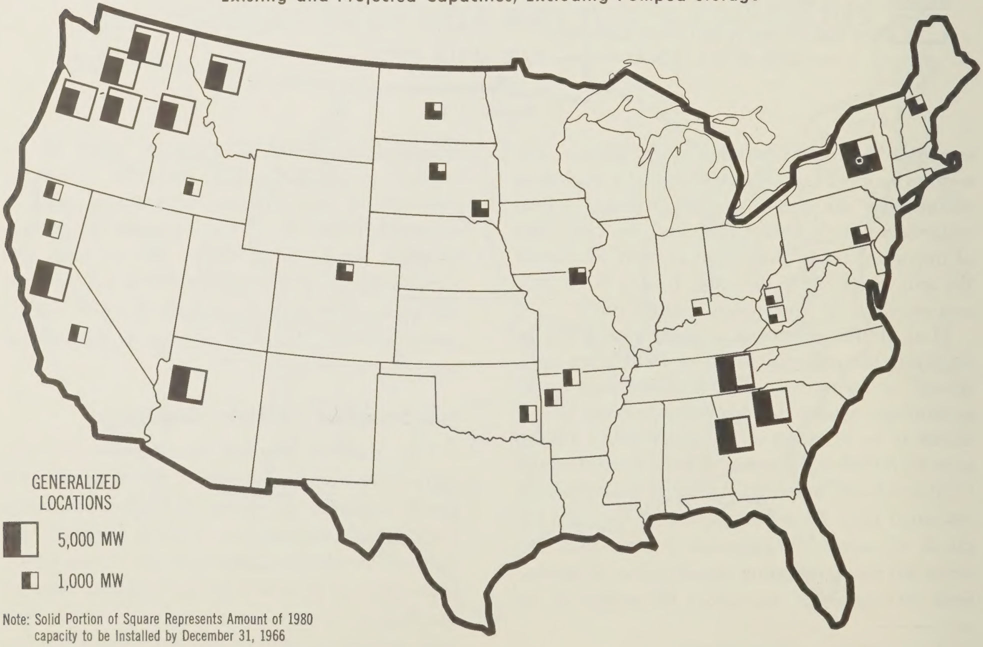
[3] Advisory Committee Report No. 7, by the Generating Stations Special Technical Committee, 1963, p. 57 of Part II.



HYDROELECTRIC CAPACITY-1980

Existing and Projected Capacities, Excluding Pumped Storage

Note: Solid Portion of Square Represents Amount of 1980 capacity to be Installed by December 31, 1966

Figure 112

33 million kilowatts, which amounts to about 11 percent of the total required additions for this period. About 50 percent of this amount is projected for the Pacific Northwest (see table 37, area P). Outside the Northwest, new hydroelectric capacity will be used primarily to serve peak loads; dependable capacities based on critical year flows will in general be capable of supplying power at an average load factor of about 25 percent. Northwest hydroelectric power will be serving base as well as peak loads well into the 70's, but in the later years of the decade base load thermal power will be needed to help meet total demands.

While all of the hydroelectric capacity included in the 1980 pattern are supported from knowledge of specific sites and generating capabilities, it is likely that numerous modifications will arise in later planning stages. About one-half of new hydro power will probably be built as part of Federal multipurpose development programs which require much time for planning and for Congressional authorization and funding, but there are many locations that should be economically attractive for non-federal development. About 10 percent of the added capacity will accrue from enlargement of installed capacities at projects now in operation. The Pacific Northwest and the Southeast are the areas most likely to be concerned with new hydroelectric opportunities by 1980. Two-thirds of all new hydroelectric capacity are likely to be constructed in these areas.

Pumped Storage Capacity

Capacity supplied from pumped storage projects—comprising about four percent of total 1980 requirements—will be most closely associated with areas having high proportions of thermal generation, limited hydroelectric power and proximity to suitably rugged terrain. Pumped storage will be in close economic competition with other forms of peaking capacity, notably new thermal plants especially designed for producing peaking capacity for short intervals, new large size gas turbines and also conventional large steam plants used for peaking purposes. Pumped storage projects can be expected to require less maintenance than steam-electric units and therefore should be available for service for a higher percentage of the time. They are flexible in operation and within the limits of capacity and pondage are ideally suited for following the rapid fluctuations in demand at time of system peaks. These projects can often supply large blocks of capacity. The existence of strong regional transmission grids will greatly facilitate the economic feasibility of pumped storage projects by minimizing transmission costs.

Power Imports

At the present time less than 500 megawatts of power are imported from Canada. The 1980 pattern for generation includes the importation of 4 million kilowatts of hydroelectric power from Canada. This amounts to only some one percent of the total U.S. energy requirements projected for 1980. In October 1963, the Canadian government announced a policy of moving forward with the development of large low-cost power sources within Canada, and of encouraging the export of surplus power to the United States and the construction of the necessary interconnections between Canadian and U.S. Power Systems in order to induce early development of Canadian resources.

Subsequently various discussions between power planning groups in Canada and the United States have taken place. It appears likely that within the next ten years, power in the following locations and amounts could be made available to U.S. markets for firm periods up to 25 years and at prices which would be mutually advantageous to both countries.

Location	*Amount–Mw.*
Hamilton Falls, Newfoundland via Quebec	2, 000 to 4, 000
Nelson River, Manitoba	1, 000 to 2, 000
Peace or Columbia River, British Columbia	1, 000

In addition to mutually beneficial power sales, stronger interconnections would permit adjacent systems in the two countries to enjoy the additional advantages of coordinated planning and operation. Substantial benefits would accrue from diversity and reserve savings.

It should be emphasized that the foregoing, as well as all other projections in this report involving facilities or transactions, represents only generalized consideration of the factors involved, and is not to be construed as Commision (or staff) approval or endorsement of particular projects or plans.

Nuclear Capacity

Approximately 70 million kilowatts of nuclear capacity has been included in the general pattern for 1980, constituting about 13 percent of the total installed capacity needed at that time. Nuclear plants operating in the base of the load at an average capacity factor of 85 percent are expected to supply about 19 percent of the energy needs in 1980. These estimates are about 70 percent greater than the general projections contained in the National Power Survey Advisory Committee Report No. 15[4] on Nuclear Development and in the Atomic Energy Commission's Report to the President, 1962, on Civilian Nuclear Power.

The Advisory Committee in 1963 summarized the present uncertain but nevertheless promising outlook for future growth in nuclear power as follows:

"The present report has been limited to the period to 1980, considering essentially the water moderated and cooled reactors. However, many other reactor types are in varying stages of development. Should any of these concepts prove economically more attractive than the water type the result will be to accelerate the growth of nuclear capability during this period.

"There is now sufficient operating experience on certain types of converter reactors to provide a basis for confidence in the reliability and flexibilty of such plants for central station service, and to encourage confidence in the ultimate attainment of good economy. This basis of operating experience is expanding rapidly both in terms of kilowatt-hours of generation and in terms of the range of nuclear technology represented.

"It is noted that while at least some types of nuclear plants can be built in very large sizes, the application of current guidelines restricts the availability of suitable nuclear plant sites. As more operational and test data are obtained, and improvements in design achieved, this problem should be greatly reduced.

"Areas of high fuel cost will be the first to increase their nuclear capacity, but when nuclear costs are sufficiently reduced, other areas are likely to install nuclear capacity. In some cases it may be that reasons other than cost, perhaps such as the reduction in air pollution, will play a part.

"It appears that with a vigorous development in breeder reactors, the fast breeder has the potential of being economically competitive as well as contributing importantly to the extension of our uranium resources for the future demands for electric power. . . ."[5]

In the brief time since the Advisory Committee report was prepared in the early part of 1963, a number of developments have occurred which indicate that the committee's general projections for nuclear capacity in 1980 may have been too conservative. Foremost among these are the results of bids for the Oyster Creek nuclear plant of Jersey Central Power and Light Company, which place a point on the index of projected nuclear generation costs substantially lower than other prior reference points.

Table 54 summarizes the amounts of nuclear power assumed in this analysis for each load study area. Assumed choices between nuclear power and conventional steam-electric generation were made largely on the basis of comparison of both investment and operating costs. Trends in future costs of conventional fuels and construction of conventional plants have been assumed to be downward but not at the same rate of decrease as for nuclear stations. In a few instances, involving supply for densely populated metropolitan areas, it was judged advisable to project nuclear energy sources beyond strict economic indications. Such plants, located in the fringe of metropolitan areas, could assist in meeting total loads without contributing further to the problem of air pollution.

As table 54 indicates, nuclear power is expected to make a strong showing in New England, Florida and the West coast. These are areas where generating costs are sufficiently high to permit present or early nuclear plants to be competitive. Some utility executives in these areas look upon nuclear power as a principal source of electric energy supply from now on. They view nuclear plants and production costs as having a greater opportunity for future cost reduction than thermal generation under the fuel supply situations which now exist. We have also projected that nuclear power will make a moderate entrance into the Great Lakes and mid-continent region. The val-

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[4] Prepared by the Generating Stations Special Technical Committee, 1963.

[5] Advisory Committee Report No. 15, pages 177 and 178 of Part II.

TABLE 54

Estimated Nuclear Capacity in 1980

(Capacity in mw)

Coordination study area and sector	Reactor size in mw 0 to 400	 400 to 800	 800 to 1200
A—New England	150	2, 000	3, 000
B—New York	255	....	7, 000
C—Pa.-N.J.-Md	51	600	5, 800
D—Ohio Valley	....	....	5, 000
H—Lower Michigan	225	....	2, 000
Northeast sector	681	2, 600	22, 800
E—Carolinas-Virginia	....	2, 400	....
F—Tennessee Valley	....	500	1, 000
G—Southeastern	....	....	9, 000
J—Texas area	....	600	....
K—Middle South area	....	....	....
M—New Mexico and Panhandle	....	....	....
South sector	....	3, 500	10, 000
I—North Central	116	1, 200	8, 000
L—Upper Missouri Basin	....	400	....
O—Colorado-Wyoming area	....	600	....
North Central sector	116	2, 200	8, 000
N—Southwest	725	600	14, 200
P—Northwest	776	1, 600	2, 000
West sector	1, 501	2, 200	16, 200
Total	2, 298	10, 500	57, 000

idity of these assumptions undoubtedly will be challenged by the suppliers and transporters of fossil fuels. The final answer will depend on the vigor with which suppliers of these competing forms of generation pursue their respective advantages to achieve lower cost power.

New Steam–Electric Capacity

Conventional fossil-fuel-burning steam power plants probably will supply about 67 percent of the energy required in 1980 and 65 percent of the new capacity added between now and 1980. Thus achievement of a lower level of power costs for 1980 will depend to a large extent on continued exploitation of the greatest possible economies in steam plant construction and operation.

The industry has made tremendous strides in the past in improving the efficiency of steam plants with resulting reductions in unit costs. Continuation of the past trends to expand the sizes of generating units may have a significant effect on reducing the cost of power generation. For example, generation costs at the busbar can be reduced 40 percent on the average by an increase in unit size from 25,000 to 100,000 kilowatts and 25 percent for increasing unit size from 100,000 kilowatts to 500,000 kilowatts. Units of 1,000,000 kilowatts now being constructed are expected to produce power at even lower unit costs. It is contemplated that increases from 500,000 to 1,500,000 kilowatts would produce further cost reductions of about 12 percent. The net effect of increasing unit sizes from 100,000 to 1,500,000 kilowatts would be to reduce busbar costs by approximately one-third if our projections are correct.

Table 55 summarizes the pattern for conventional steam-electric generation for the entire United States by categories of unit size assumed in this survey. It will be noted from the table that half the steam-electric capacity will be in units of 600 megawatts and larger. The distribution of sizes is intended to approach a pattern of optimum economy in generation costs, considering the elements of load growth, transmission and reserve along with those relating to the economies of size. The pattern reflects the assumption of an aggressive approach toward coordinated planning by the industry.

TABLE 55

Pattern of Conventional Steam-Electric Capacity Projected for Service in 1980

Unit size (Mw.)	Average size of unit in each group (Mw.)	Percent of total capacity (cumulative)	Number of units	Total capacity (Mw.)
0–199	[1] 66. 8	29. 3	1, 558	104, 050
200–399	[1] 256. 7	43. 7	199	51, 090
400–599	[1] 452. 8	48. 1	33	14, 940
600–799	[1] 603. 1	55. 0	42	25, 320
800–1,000	[1] 903. 0	80. 2	99	89, 400
1,200	1, 200. 0	92. 4	36	43, 200
1,500	1, 500. 0	100. 0	18	27, 000
Total			1, 972	355, 000

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[1] Units grouped in 200-Mw. bands.

NOTE.—Half the capacity is in units of 600 Mw. and larger.

Other Capacity

This category includes such forms of generation as gas turbines, diesels, geothermal plants and the first trials of some of the direct conversion forms of electric energy production, sometimes called exotics. As outlined in chapter 8, the most promising of these for possible introduction on a beginning commercial scale by 1980 are fuel cells and magnetohydrodynamics. Extensive programs of research lie between concept and production, particularly where materials and practices might involve exposure to temperatures ranging from as high as 5000° F down to near absolute zero, about −460° F. The magnitude of any commercial production that might begin by 1980 would be very small and consequently no recognition has been taken of any specific amount.

Gas turbine power units will find some application as sources of peaking power and reserves for systems of moderate size which for good reason or poor delay interconnection and coordination with other system. The 6.8 million kilowatts assigned to the category of "other generation" is less than two percent of the 1980 capacity needs, reflecting a judgment that this group will occupy a relatively unimportant position in the total pattern.

Total Capacity

The foregoing sections have described the general considerations governing generating sources required to meet 1980 loads. The exact make-up of the several sources of generation and the portion of each is not critical so long as planning is oriented to the most economic sources on a broadly coordinated basis. The general plans developed herein result in the following overall distribution of capacity by types:

Type	*1980 percent*
1. Steam-electric (fossil fueled)	67.3
2. Conventional hydro	14.5
3. Nuclear	13.3
4. Pumped storage	3.6
5. Diesel and gas turbines	1.3
	[1] 100.0

---

[1] Excludes imports.

Energy—Capacity Relationships

Utilization of anticipated load diversities on a broadly exchanged basis could reduce capacity requirements in 1980 by 10 percent and raise the annual load factor for the nation from 62 to about 67 percent. Diligent promotion of off-peak uses might raise it even more.

While the composition of resources in each load study area generally has some characteristics which distinguish it from the average, the following summary of a typical situation illustrates the demands which may be placed on equipment for higher load factor operation by 1980.

Percent of peak load	**Power resource**	**Annual utilization percent**	**Contribution to load factor**
45	Conventional and nuclear generation added 1967–80	82.5	0.37
26	Conventional and nuclear generation added 1955–66	70	.18
17	Remaining older steam	35	.06
15	Hydroelectric	25	.04
12	Pumped storage or thermal peaking	20	.02
115 [1]			0.67

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[1] Peak load plus reserves.

The trend to higher load factors plus the reduction in reserves will reduce the relative amount of peaking capacity required in 1980. Additional peaking capacity needed beyond available new economical hydroelectric resources are assumed to be supplied primarily by appropriate thermal units and pumped storage projects, where economically available. As indicated in the summary this is not expected to be a large part of the total capacity.

General Siting Considerations

The selection of locations for generating stations involves the complex considerations of plant development with relation to fuel supplies, load centers, transmission line facilities, rail, pipeline or water transportation, cooling water supplies and, in the case of nuclear plants, adequate area for compliance with nuclear plant siting criteria and for large plants, accessibility to water transportation for shipment of the large and heavy reactor vessels.

About 40 percent of the generation which will be serving the loads of 1966 can be classed as generation near the source of the fuel. This includes, for example, the output of a large number of the plants in the coal fields of Appalachia and the Ohio and Tennessee Valleys which are located in mining areas or within short hauling distances, and energy from generating plants located near the natural gas fields of the mid-south states of Texas, Oklahoma, Kansas, Arkansas, and Louisiana.

The choice between locating generation at the fuel source or at load center has in the past been determined by economic comparisons relating to the cost of delivering energy to the load by fuel transport as opposed to transport of energy by wire. These are still the main considerations, but the comparisons have been sharpened by improved efficiencies and reduced costs among the competing forms of transportation, and alternative choices in types of generation.

Several additional factors are beginning to have some influence in the selection studies. As metropolitan areas grow, the requirements for controlling pollutants are becoming more exacting and good metropolitan area sites will become less available and more expensive.

Generating stations located on the fringe of a large metropolitan area may avoid some of these problems for a time. In so doing, however, they lose the economic advantage of shorter underground runs for delivery of bulk power to main city substations, the primary advantage of an "in city" site. Longer runs of costly underground transmission cables are required from plants in the fringe area, and in some cases, New York City, for example, the same higher entrance cost must be incurred for any non-city plant whether on the metropolitan fringe or at a more remotely located mine-mouth site. All in all, considering the problems and costs attendant on city locations, the cost reduction being made in supplying power from alternative generating plants near fuel sources, and the advantages of strong interconnections at major load centers for diversity and reserve support, the requirement for substantial underground city entrances appears unavoidable. Thus, in a broad view of future facility requirements it is difficult to overstress the need for continued improvements in underground cable design to increase carrying capacities and to reduce construction and maintenance costs.

In evaluating the relative economy of mine-mouth generation, the opportunity for multiple use of transmission lines from mine-mouth stations to load is an important consideration. Many lines which are now serving mine-mouth plants or remote hydroelectric installations are at the same time useful components of strong transmission networks. As such they can serve many of the additional transmission functions which may be superimposed on the grid with the growth of new loads, resources and interconnections. Incorporation of such lines into grids is particularly evident in the plans of systems having generating plants in the extensive coal fields of Appalachia. While multiple use loading cannot be imposed upon transmission lines without providing adequate design capacity, added capacity can usually be built into lines at relatively small additional cost and considerable economy can thus be gained through such joint utilization.

The construction of large power plants and accompanying transmission facilities represent major investments. An essential feature for the utilities and their customers is a long-term contract for a major portion of fuel requirements or other firm assurances of fuel supply at reasonable cost. In view of the assured large scale market for coal of several million tons a year which are provided by such a plant, coal mining operators, in return, can afford the investments and research which will continue to lower the cost of fuel. Likewise, low transportation costs on a firm basis that take advantage of the savings in unit train movements of coal to large plants are a key element in the economic feasibility of sites at any appreciable distance from the coal fields but closer to load centers. Thus, economy of scale of both the plant and its fuel or energy transport becomes important to all participants in any steam power plant projects.

Operating Characteristics of New High Efficiency Generating Plants

Generally as steam plants grow older they are used less of the time because the newer units are more efficient and therefore are used for the base load. It is possible however that new high temperature and high pressure conventional thermal electric units in sizes of 500 megawatts to 1,000 megawatts and larger may be operated at relatively high load factor for more of their life cycle than steam-electric units in the past. Modern new units of large size have thermal efficiencies in the range of 8,700 to 9,000 British thermal units per kilowatt-hour, which at the lower limit corresponds to an overall plant efficiency of nearly 40 percent. This approaches the generally recognized practical upper limit of about 45 percent. Increasing temperatures to 1200° F and pressures to 5000 psi will lower heat rates to 8500 British thermal units or slightly lower, only a marginal improvement as compared with the difference between today's new plants and the plants of 20 and 30 years ago with heat rates of 12,000 and 13,000 British thermal units. It is likely, therefore, that today's new large plants will not incur as rapid a rate of obsolescence and will run their life course at somewhat higher average load factors than their predecessors. In areas where nuclear generation may soon become the predominant new source of added capacity, the likely lower cost of nuclear fuel may tend to shorten the time of baseload operation of large conventional plants.

Attainment of higher efficiencies has resulted in units which are somewhat less flexible in operation. For good performance, the high efficiency units generally are limited to operating between about 65 and 105 percent of rated load. The change from a minimum operating level of say 30 percent to full load, and the corresponding load reductions, can require as much as one to two hours.

Most nuclear powered units built during the next 10 years can be expected to be more flexible in following the load over a wider range of the operating scale. The lower temperatures and pressures of the nuclear units now on the market place less strain on the equipment and less demand on materials than the higher temperatures and pressures of the large high efficiency conventional units. While this is a desirable characteristic for meeting unusual or unexpected load changes, nuclear generation operating in a mixed system would probably be base loaded because of lower fuel costs. Also, as progress is made toward improving the efficiency of nuclear energy conversion, steam conditions may be raised to limits more comparable to those of today's large conventional units.

Unit Size Considerations

The selection of unit sizes assumed for this study has been based on the expected gradual increase in size availability and upon the rate of load growth in the area. In no case have sizes been controlled by the needs of a single system, but rather by the needs of the systems serving a large load center area or group of load areas, on the assumption of full coordination within the area or areas. Only a few individual systems can be expected to have load growths which can economically absorb the output of units in the range of 1,000 megawatts to 1,500 megawatts. The selection of unit sizes in the maximum range generally followed the projections contained in the report of the Generating Stations Technical Advisory Committee and extended over a range of 1,000 megawatts in 1967 to about 1,500 megawatts a few years prior to 1980. Nuclear units were held to somewhat smaller sizes, the maximum ranging from 500 megawatts in 1967 to about 1,200 megawatts a few years prior to 1980. The latter figure compares with the committee's suggestion of 1,000 megawatts.

Some allowances have been made for units of moderate capacities in the range of 200 megawatts to 300 megawatts for broad areas of relatively light loading where energy transmission costs from larger capacity installations would be unduly high.[6] In these circumstances they have economic justification. Smaller units have not been included however where there is no economic justification. Our projections assume that the various individual systems or groups of entities will cooperate to achieve the benefits of scale in their sources of supply.

Transmission Planning

Adequate interconnection between systems is of paramount importance to transmit the planned and emergency exchanges of a well coordinated power supply industry. However, coordination does not necessarily require the construction of a large number of EHV transmission lines over which there is a continual long distance mass movement of electric energy. True, there are some instances especially in the West where the supply and loads will call for fairly long distance transmission. But the average kilowatt-hour generated under a fully coordinated operation should move little farther to reach its load than it does at present. In many situations it may move a lesser distance. Coordination opportunities can frequently be provided with relatively short interties.

All major systems in the eastern two-thirds of the United States are interconnected and many of them have agreements with neighboring systems for varying degrees of coordination. Some systems, however, while interconnected within their own States do not participate in any regular exchanges with systems across state boundaries, despite the rather clear potential advantages of such interties. Here it appears that failure to interconnect may reflect an attempt to avoid federal regulation rather than a decision based on engineering or economic considerations.

All principal systems on the west coast are interconnected but the tie between the Pacific Northwest and the Pacific Southwest is presently limited to 60 megawatts. However, the inability to exchange large amounts of available energy and capacity between these regions will be overcome by the construction of the recently approved NW–SW intertie program.

The general capability of the transmission network today is illustrated in two transmission charts, figure 113, which displays all transmission lines of 161 kilovolts and higher voltage, and figure 114 which shows only the lines of 230 kilovolts and higher. Many utilities have recently announced plans for EHV additions within their own systems and in some cases for interconnections with neigh-

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[6] The size mix of generating units for 1980, as selected for the 16 study areas, is depicted graphically in figure 105 of chapter 14.

PRINCIPAL ELECTRIC TRANSMISSION LINES 1962

161 Kv and Above

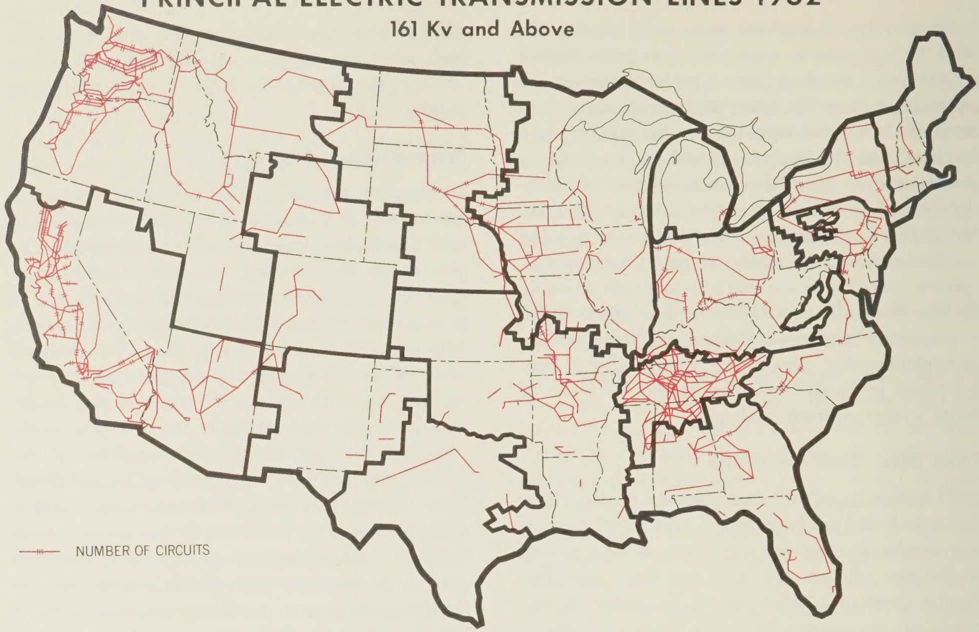
NUMBER OF CIRCUITS

FIGURE 113

PRINCIPAL ELECTRIC TRANSMISSION LINES 1962

230 Kv and Above

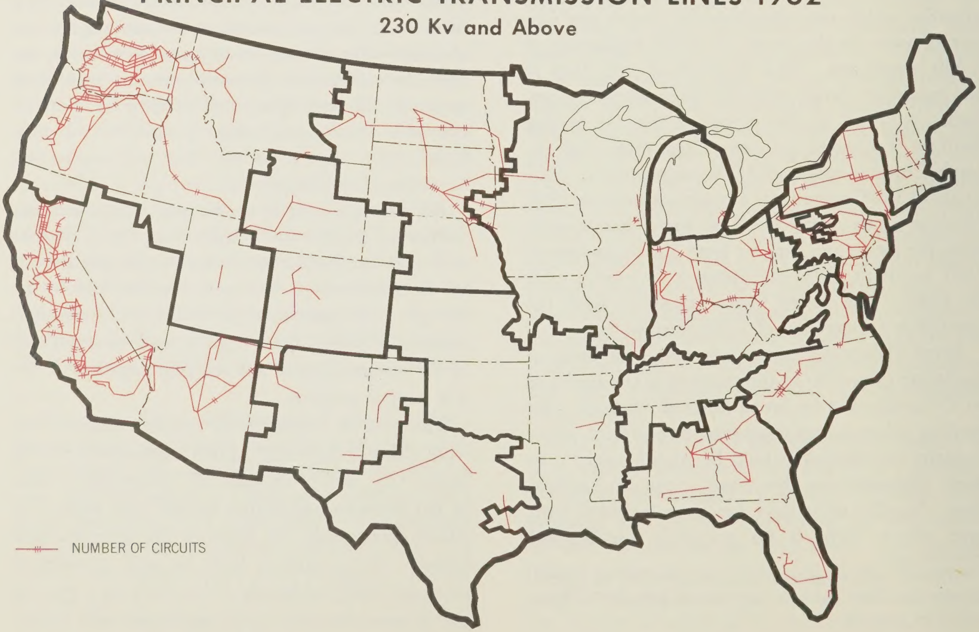
NUMBER OF CIRCUITS

FIGURE 114

boring systems. Many of these lines are under construction and within a period of three or four years the extent of EHV transmission lines will be more than doubled.

The maps shown in figures 113 and 114 do not show all transmission lines in the country. In fact, a map of all such lines which would include 66 kilovolts and higher would be a maze of lines that would resemble a highway map. In many situations, these lower voltage lines are adequate. However, they cannot permit more than a small part of the bulk power transfers necessary over wide areas, to exchange diversity and reduce reserves. A high degree of coordination requires a strong network of EHV lines, generally 345 kilovolts and above.

The value of a strong transmission network lies in the flexibility it offers for meeting large variations in loads, and through interconnections with others, the ability to share diversities and reserves. With the exception of lines which are designed for a permanently fixed duty such as delivery of power from an isolated generating source—and these are relatively few—it is not possible to select a precise and consistent loading program for the life of a facility. New duties invariably will be assigned as loads and networks grow. Prudent utility practice projects these requirements in the best manner possible and makes an appropriate allowance for possible future loading and for leeway required for a stable operating network.

Transmission lines are in many ways like our transportation arteries which undergo a large variation in traffic loading but because of their availability in a broadly distributed and interconnected manner permit and facilitate beneficial deliveries between all areas and broadly foster the economic growth of the nation. Many types of power transactions may take place on an adequately planned transmission network and, if available, it encourages and may even be a compelling factor in consummating the exchange agreements.

An adequate network will facilitate the adjustment that invariably is required for miscalculations of load growth, emergencies, or sudden changes in major loads and will permit the adjustment to be spread through a maximum area. It is not inconsistent to seek the last calculable measure of economy in the construction of generating facilities but at the same time to make reasonable allowances for future contingencies and growth in planning transmission.

Figure 116 portrays a possible pattern of an EHV network to meet the load conditions projected for 1980. The pattern shown is not based upon detailed economic or engineering studies; it is only one configuration among a variety of alternatives that could have been selected but is considered to be a suitable pattern upon which to base the overall transmission estimates for the survey study. While it reflects in many respects the general transmission networks suggested by the several regional advisory committees, the major interconnections between the three eastern sectors and the west sector were developed subsequent to the regional planning submittals. Further studies should be made to determine the location and the feasibility of all the lines shown and these major interconnections in particular. In view of the foregoing, we emphasize that figure 116 should be regarded as a presentation of possibilities rather than a blueprint.

It will be noted that voltages in the network range from 230 kilovolts to a few lines at 700 kilovolts with intervening levels at 345 kilovolts and 500 kilovolts. There has been some suggestion of standardizing EHV at some level such as 500 kilovolts. This we do not support. The variations in power transfer requirements, line length and existing system facilities are too extreme to justify any restriction to a single EHV level. Advisory Committee Report No. 9[7] comments on the question as follows:

"The use of just one standard EHV voltage is not recommended. All three of the voltage levels indicated (345, 500 and 700 kv) should be applied as appropriate and as the economics of a particular area or situation or both may dictate. The fact that 500 kv is relatively close to 345 kv should not be troublesome in that 500 kv is an appropriate overlay to existing 230 kv and, in some instances, 138-kv systems, just as 700 kv is an appropriate overlay to 345 kv. Super-position of 700 kv on existing or proposed 345-kv systems is a logical and economical future step in that it provides increased capability in the order of four to five times that of a 345-kv system. In all probability, such superposition of 700 kv on 345-kv systems will not be required until the 1975–1980 period." [8]

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[7] Report entitled "Extra-High Voltage Levels Recommended as Standards and Maximum Voltages Recommended for Consideration in the Survey," prepared by Transmission and Interconnection Special Technical Advisory Committee, 1963.

Network planning in the more densely loaded areas of the eastern half of the United States is mainly concerned with high capacity transmission for relatively short distances. Many lines will be carrying normal peak loads of 500 to 1,000 megawatts in 1980, and distances from new large generating plants to major load centers will average 50 to 100 miles. Transmission interconnections between closely coordinated systems encompassing different study areas will have capacities equivalent to about 20 percent of the average capability of the associated areas. In most instances, this magnitude of capacity is adequate for all types of exchanges including diversity and reserve interchanges, unit sharing and economy and emergency transfers.

Transmission patterns in the populated areas on the west coast are similar in general plan to the eastern network, but interconnections between the northwest and southwest and between the western areas and the midwest and midsouth would require much longer transmission facilities. Analyses indicate that ties between the Pacific Northwest and Pacific Southwest would show immediate benefits sufficient to justify a tie of 1,200 megawatts and that by shortly after 1970 an exchange capacity of 4,000 megawatts will be usable.

Transmission Network Functions

The transmission network visualized for 1980 will serve the following six functions:

1. *Permit the construction of larger and more economical generating units and the transmission of bulk power from generating sources to major load centers.* One of the most important consequences of interconnection and coordination is the ability of individual systems to construct larger and more efficient generating units than would otherwise be possible, through joint planning and adoption of staggered construction schedules. This greater emphasis on larger thermal generating units and mine-mouth locations will require strong EHV transmission facilities and interties. While hydroelectric capacity will grow substantially, the fraction of total load it supplies will diminish. Hydroelectric growth has always placed and will continue to place heavy demands on high voltage network planning in many areas, but it will become of lessening importance in shaping future transmission patterns.

2. *Permit reduced reserve requirements by the sharing of capacity between areas and sectors.* The average reserve needed under coordinated operation on a national scale is 14 or 15 percent of the coordinated peak with the large 1,000 to 1,500 megawatts units assumed for 1980. If isolated area operation were assumed, the installed reserve would be much larger, unless the unit sizes were sharply curtailed. The interconnections between any area and those surrounding it therefore should have sufficient capacity to import the full differential between the area's installed reserve and the area's maximum computed reserve requirement.

3. *Provide capacity savings by seasonal exchange of capacity between areas which have opposing summer and winter peaks.* Such transmission involves a two-way flow, generally an equal exchange. To minimize transmission requirements, the optimum of exchange would be equal to one-half of the difference between the summer and winter peaks in the area which has the smaller seasonal difference. Each interconnected area thus depends upon meeting its predominant seasonal peak partly through its own capacity and partly through the diversity exchange. Under some circumstances where distances between exchange areas are long, the exchange may be transferred by displacement of intermediate capacity. Potential 1980 seasonal diversity power flows are shown in figure 115.

4. *Permit capacity savings from time zone and random diversity.* The exchange of capacity between time zones will require a two-way movement of power and for full utilization will require displacement over long distances encompassing all four time zones. Some systems which now extend into two time zones or have interconnections across a time zone boundary may be receiving a small benefit in time diversity. Effective use of time zone diversity will depend upon detailed analyses of future loads by time zones, adequate interconnections between areas across the continent, and establishment of procedures for the coordinated planning and monitoring of interchanges between zones.

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[8] Advisory Committee Report No. 9, p. 83 of Part II.

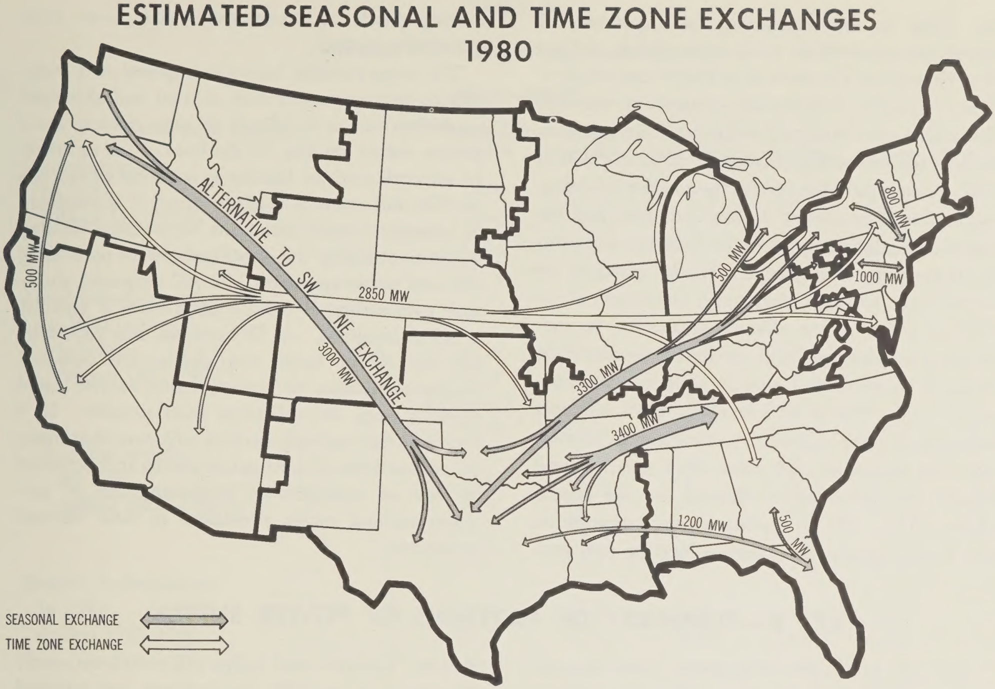


FIGURE 115

The time zone diversities available in 1980, and discussed in chapter 13, reveal the necessity for substantial transfers between systems in the Pacific coastal sector and those in the mid-continent and east coast sectors if any substantial capacity savings are to be made as a result of this factor. The potential magnitude of east-west interchange, when utilizing 50 percent of the estimated time zone diversity will be about three million kilowatts each way. This represents a potential reduction in capacity of nearly six million kilowatts. The relative contribution of offpeak capacity from each zone would be generally related to the capacity in the zones. Hence the contribution from the Rocky Mountain area would be much less than from others and the benefit that the area could receive in return would be in proportion.

The potential pattern of time zone and random diversity power flows in 1980 is depicted in figure 115.

It is anticipated that random diversity would be largely exchanged on a local basis, within an area or within several areas, and ordinarily would not require procedures for hourly monitoring beyond those normally employed in coordinated dispatch. Further accumulation and analysis of detailed load data is required to demonstrate the magnitude of the diversity and thus be a guide for planning with confidence the lesser capacity needed to meet the coordinated load.

5. *Facilitate the transmission of offpeak energy.* Such uses would include economy exchanges where the aggregate of fuel and operating costs and transmission losses result in a favorable balance, the transfer of surplus hydroelectric energy by offpeak deliveries to pump storage projects, and similar cost saving exchanges. Having established a network that is adequate for the capacity transfers summarized under paragraphs 1 to 4 above, it should be possible to utilize all excess secondary hydroelectric energy and more broadly distribute the energy available from low cost fuel areas. The important resulting savings are summarized in chapter 17.

6. *Provide the flexibility to meet unforeseen demands.* A strong interconnected grid over broad areas of the country provides additional benefits on which a price tag cannot be placed but which are of great importance to the industry and the pub-

lic. Here we are considering the importance of strong interconnections to meet completely unforeseen changes in demands of a major magnitude—either increases or decreases—changes in demands that might arise from national defense emergencies, such as the recent sharp cutbacks in production at AEC gaseous diffusion plants, from major miscalculation of load projection in localized areas, and the location or relocation of a major industry, and similar important contingencies. In the event of an extreme air pollution emergency, generation at individual plants in the affected area could be curtailed or even stopped with power continuing to be available from distant sources over the interconnected grid. This is an advantage which becomes increasingly more important as increases in population and industrial and automotive activity send heavier concentrations of effluents into the atmosphere. Also, with an existing strong transmission grid there is greater flexibility in locating new generating plants at advantageous sites away from population centers.

The many variable functions imposed on a transmission network under both normal and abnormal conditions makes it difficult in most cases to set a precise design loading for the lines of the network. In network analyses leading to selection of line capacities and network configurations, it is necessary to introduce many variations in potential loading to assure attaining the combined goal of reasonable cost and stable operation. In AC networks, short-time overloading is usually permissible if stability is not endangered. In DC systems, line capacities are capable of major overloading but terminal equipment cannot be pressed much beyond rated capacity even for relatively short periods. It is expected that network analyses will show that many of the functions of coordination can be accomplished by new or strengthened interconnection of networks without major alterations in their internal structure.

PART B—SUMMARY OF PATTERNS OF POWER SUPPLY

This part of chapter 15 presents a brief general summary of conclusions resulting from the analyses of the 16 coordination study areas and the four geographic sectors, into which the country has been divided for convenience of analysis.

The more detailed results of applying the major planning concepts of the National Power Survey in projecting the growth of the electric power industry to 1980 are presented in subsequent sections of this chapter for each of the four geographic sectors—(figure 110). The presentation for each sector includes a summary of the load requirements, present power supplies, description of utilities, pooling arrangements, utilities' early development plans, and the future generation and transmission patterns assumed for this Survey.

The Pattern of Generating Capacity

Table 56 shows the projected make-up of the generating capacity required in 1980 by sectors and in summary for the U.S. fossil-fueled steam-electric plants are expected to provide about 67 percent of the needed capacity, of which about 17 percent is shown to be at mine-mouth. Nuclear power is estimated to form about 13 percent of total capacity with the larger amounts in the Northeast and West Sectors. Conventional hydro will contribute nearly 15 percent of the 1980 requirements and pumped storage hydro and other peaking sources will provide the remainder. Regionally, the Northeast and the South Sectors account for about 35 and 32 percent of the U.S. total, the North Central Sector 15 percent, the West Sector 18 percent. Figure 116 shows the generalized location of major centers of generation to 1980 together with a possible pattern of transmission. The present location of major load centers (figure 117), was an important factor in the development of the 1980 generation and transmission pattern.

Our studies reveal several broad trends—the concentration of hydroelectric resources in the Western and Southern Sectors, the concentration of added nuclear projects in the coastal areas, the continued major dependence on fossil fuel steam-electric generation in the central areas of the nation and the moderate demands for peaking resources in the form of pumped storage and other special peaking facilities. In terms of generating capacity to be added from 1967 to 1980, hydroelectric plants are expected to provide 11 percent of the total, fossil-fuel plants 60 percent, and nuclear plants 22 percent.

TABLE 56

Estimated U.S.[1] Generating Capacity 1980

(Gigawatts [3])

Generating capacity	Northeast sector	South sector	North central sector	West sector	Total	Percent
Hydroelectric:						
In 1966	6.7	10.2	3.9	21.8	42.6	8.2
Added 1967–1980 [2]	3.5	6.8	0.2	22.7	33.2	6.3
	10.2	17.0	4.1	44.5	75.8	14.5
Fossil fueled steam:						
At load center:						
In 1966	53.0	57.4	21.9	18.9	151.2	28.9
Added 1967–1980 [2]	40.8	51.2	14.8	7.0	113.8	21.8
	93.8	108.6	36.7	25.9	265.0	50.7
At mine mouth:						
In 1966	13.9	4.5	2.0	0.5	20.9	4.0
Added 1967–1980 [2]	22.8	18.9	19.0	5.0	65.7	12.6
	36.7	23.4	21.0	5.5	86.6	16.6
Nuclear fueled steam:						
In 1966	0.8	0.0	0.3	1.5	2.6	0.5
Added 1967–1980 [2]	25.3	13.4	10.0	18.4	67.1	12.8
	26.1	13.4	10.3	19.9	69.7	13.3
Pumped storage:						
In 1966	0.6	0.1	0.4	0	1.1	0.2
Added 1967–1980 [2]	10.9	4.0	2.0	1.0	17.9	3.4
	11.5	4.1	2.4	1.0	19.0	3.6
Other peaking:						
In 1966	1.2	1.5	1.4	0.2	4.3	0.8
Added 1967–1980 [2]	1.4	0.7	0.5	0	2.6	0.5
	2.6	2.2	1.9	0.2	6.9	1.3
Total:						
In 1966	76.2	73.7	29.9	42.9	222.7	42.6
Added 1967–1980 [2]	104.7	95.0	46.5	54.1	300.3	57.4
	180.9 [4]	168.7 [4]	76.4 [4]	97.0 [4]	523.0 [4]	100.0

[1] Excludes Alaska and Hawaii; also excludes imports from Canada.

[2] Additions less retirements.

[3] Millions of kilowatts.

[4] The capacity provided for each sector takes into account diversity savings, potential imports from Canada and the relative difference in reserve requirements for hydroelectric and thermal capacity.

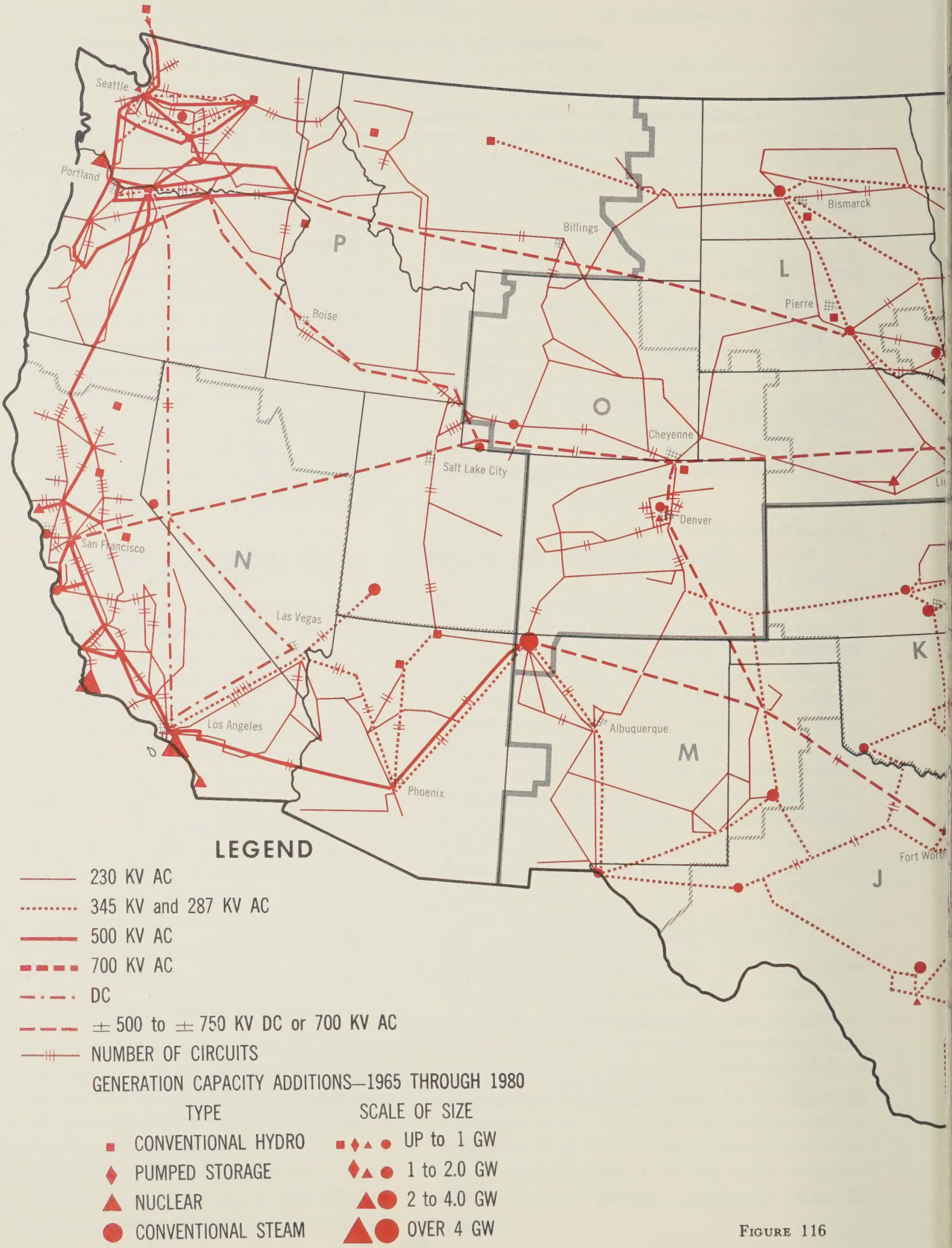
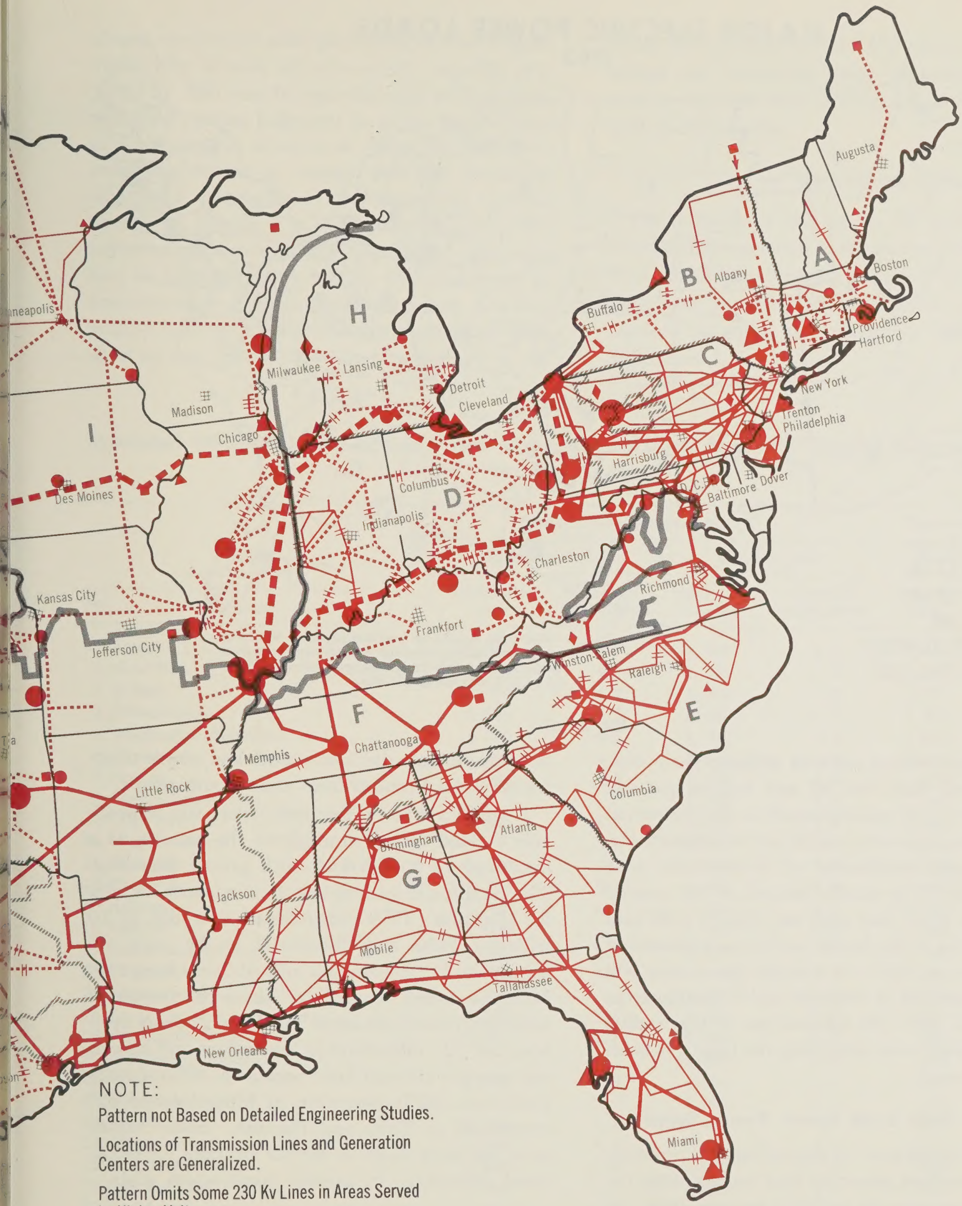

Seattle
Portland
Boise
Billings
Bismarck
Pierre
Cheyenne
Salt Lake City
Denver
San Francisco
Las Vegas
Los Angeles
Phoenix
Albuquerque
Fort Worth
P
L
O
N
M
K
J
LEGEND
230 KV AC
345 KV and 287 KV AC
500 KV AC
700 KV AC
DC
± 500 to ± 750 KV DC or 700 KV AC
NUMBER OF CIRCUITS
GENERATION CAPACITY ADDITIONS—1965 THROUGH 1980
TYPE
SCALE OF SIZE
CONVENTIONAL HYDRO
PUMPED STORAGE
NUCLEAR
CONVENTIONAL STEAM
UP to 1 GW
1 to 2.0 GW
2 to 4.0 GW
OVER 4 GW

FIGURE 116


Augusta
A
Boston
B
Albany
Buffalo
Providence
Hartford
C
New York
Trenton
Philadelphia
neapolis
H
Milwaukee
Lansing
Detroit
Cleveland
Madison
I
Chicago
Harrisburg
Des Moines
Columbus
D
D.C.
Baltimore
Dover
Indianapolis
Charleston
Richmond
Kansas City
Frankfort
Jefferson City
Winston-Salem
Raleigh
E
F
Memphis
Chattanooga
Little Rock
Columbia
Atlanta
Birmingham
G
Jackson
Mobile
Tallahassee
New Orleans
Miami

NOTE:

Pattern not Based on Detailed Engineering Studies.

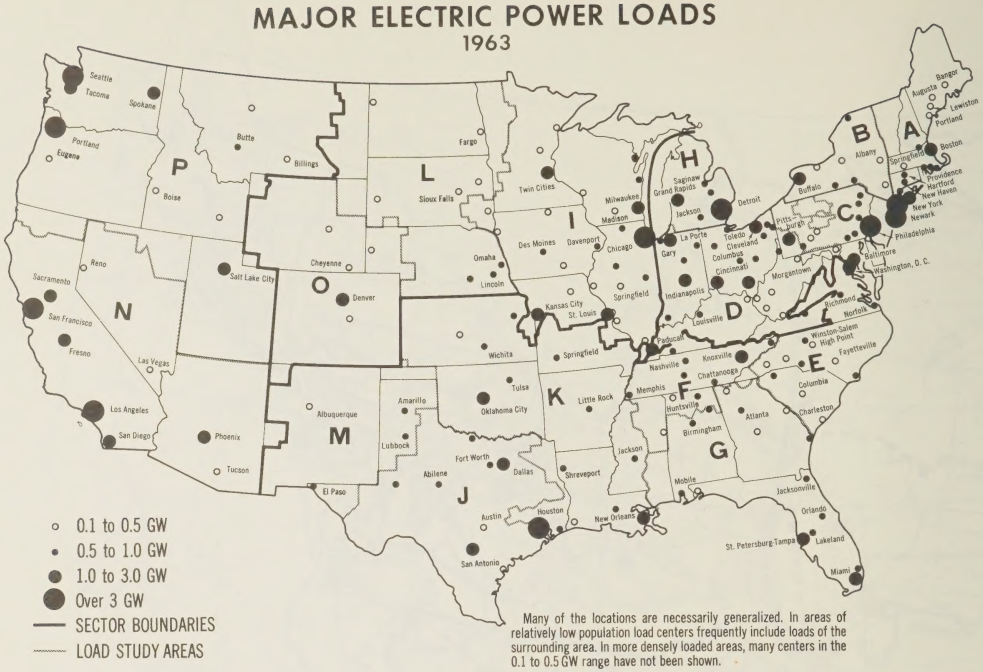
Locations of Transmission Lines and Generation Centers are Generalized.

Pattern Omits Some 230 Kv Lines in Areas Served by Higher Voltages.

Northwest-to-Texas Tie is an Alternative to the Northeast-to-Texas Tie for Seasonal Diversity Interchange.

POSSIBLE PATTERN OF GENERATION AND TRANSMISSION BY 1980

230 Kv and Higher


MAJOR ELECTRIC POWER LOADS
1963
Seattle
Tacoma
Spokane
Portland
Eugene
Butte
Billings
Boise
Fargo
Sioux Falls
Twin Cities
Milwaukee
Madison
Saginaw
Grand Rapids
Jackson
Detroit
Albany
Springfield
Bangor
Augusta
Lewiston
Portland
Boston
Providence
Hartford
New Haven
New York
Newark
Philadelphia
Baltimore
Washington, D. C.
Buffalo
Pittsburgh
Toledo
Cleveland
Columbus
Cincinnati
Morgantown
La Porte
Gary
Chicago
Des Moines
Davenport
Omaha
Lincoln
Reno
Sacramento
San Francisco
Fresno
Las Vegas
Los Angeles
San Diego
Phoenix
Tucson
Salt Lake City
Cheyenne
Denver
Albuquerque
Kansas City
St. Louis
Springfield
Indianapolis
Louisville
Richmond
Norfolk
Winston-Salem
High Point
Fayetteville
Paducah
Nashville
Knoxville
Chattanooga
Memphis
Huntsville
Birmingham
Atlanta
Columbia
Charleston
Wichita
Springfield
Tulsa
Oklahoma City
Little Rock
Amarillo
Lubbock
Fort Worth
Dallas
Abilene
El Paso
Shreveport
Jackson
Mobile
Jacksonville
Orlando
Austin
Houston
New Orleans
San Antonio
St. Petersburg-Tampa
Lakeland
Miami
A
B
C
D
E
F
G
H
I
J
K
L
M
N
O
P
○ 0.1 to 0.5 GW
• 0.5 to 1.0 GW
● 1.0 to 3.0 GW
⬤ Over 3 GW
SECTOR BOUNDARIES
LOAD STUDY AREAS

Many of the locations are necessarily generalized. In areas of relatively low population load centers frequently include loads of the surrounding area. In more densely loaded areas, many centers in the 0.1 to 0.5 GW range have not been shown.

FIGURE 117

For new generating capacity utilizing fossil fuels, it is expected that coal, oil and natural gas will share in the supply approximately in the proportion of 75 percent, 5 percent, and 20 percent respectively. The geographic distribution will be much the same as now with oil generally limited to the coastal areas where other fuel costs are higher, with coal predominating in the heavy load areas surrounding the extensive coal fields in a broad east to west belt from Pennsylvania to Arkansas and in certain areas in the West, and with natural gas as the leading fuel in the load areas bordering the large gas fields in the Southwest.

Cost of High Load Factor Power Supply

The anticipated cost[9] of generating and transmitting bulk baseload power to load centers using the facilities expected to be available between 1975 and 1980 is summarized in table 57. The costs for three alternative power sources are indicated where appropriate, namely, power from fossil fuel and nuclear plants near the load centers and power transmitted to load centers from mine-mouth plants.

A significant fact is that bulk power will be available at load centers throughout the country at a maximum of 5 mills/kwh with private financing. The variation in nuclear costs from a low of 3.2 mills for Memphis (TVA construction) to a high of 5.0 mills for Tulsa and Phoenix is, in the main, attributed to (1) much lower annual fixed charges for Memphis based on Federal financing, compared with the privately financed Tulsa and Phoenix projects, and (2) differences in investment and operating costs per kilowatt hour because of differences in unit sizes—1,000 megawatts at Memphis and 600 megawatts at Tulsa and Phoenix. Some adjustment has been made at various locations for recognized differences in general construction costs.

Mine-Mouth Generation

The general locations of new mine-mouth plants which may become a part of the power generation program by 1980 are suggested in figure 118. As observed in table 57, the cost of mine-mouth generation plus transmission is in many instances closely competitive with generation at load centers. Hence the amount of mine-mouth capacity projected by 1980 must be regarded only as illustrative, reflecting current judgment as to the future status of a competitive situation in which the balance is constantly subject to change. We are projecting that about 25 percent of new generating capacity needed by 1980 will be mine-mouth plants. The influence of mine-mouth generation on the economy of future power programs extends beyond its contribution as a generation source *per se*. Its competitive influence will be a factor in almost all decisions on new capacity and has done much to advance the development of EHV transmission technology and competing forms of energy transport such as the unit train movements of coal and the coal slurry pipeline.

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[9] All cost projections used herein assume no general price inflation.

Size of Generating Units

For purposes of this study, the additional generating units estimated to be required for 1980 have been selected from among the larger and more efficient sizes expected to be available at the time needed, assuming the maximum degree of coordination.

TABLE 57

Estimated 1975–1980 Cost of Bulk Power Generated at Large Baseload Thermal Stations Delivered to Load Centers [1]

Load center		Conventional steam plant				Nuclear plant	
		Mine-mouth		Load center		Load center	
No.	Name	Unit size mw	Energy mills/kwh	Unit size mw	Energy mills/kwh	Unit size mw	Energy mills/kwh
1	Boston	1,500	5.7	1,500	5.3	1,000	4.6
2	New York	1,500	4.9	1,500	4.9	1,000	4.6
3	Buffalo	1,500	4.7	1,000	5.0	1,000	4.5
4	Philadelphia	1,500	4.7	1,500	4.5	1,000	4.5
5	Washington-Baltimore	1,500	4.5	1,500	4.5	1,000	4.5
6	Cleveland	1,500	4.9	1,000	4.5	1,000	3.8
7	Detroit	1,500	4.9	1,500	4.5	1,000	3.8
8	Saginaw-Bay City	....	....	1,500	4.5	1,000	3.8
9	Ohio River	1,500	3.8	1,500	3.8	1,000	3.8
10	Winston-Salem	....	....	*1,200	5.0	1,000	4.1
11	Memphis	1,500	3.0	1,000	3.4	1,000	3.2
12	Knoxville	1,500	2.8	1,000	3.0	1,000	3.2
13	Atlanta	1,000	4.7	1,000	4.6	1,000	4.1
14	Miami	1,000	....	1,500	4.8	1,000	3.9
15	Pensacola-Mobile	1,000	5.1	*1,000	4.8	1,000	3.9
16	Chicago	1,500	4.4	1,500	4.2	1,000	4.3
17	Minneapolis	....	....	*1,000	4.4	1,000	4.3
18	St. Louis	1,500	3.6	1,500	3.6	1,000	4.3
19	Ft. Worth-Dallas	1,000	4.4	*1,200	3.7	600	5.0
20	Houston-Galveston	....	....	1,500	3.5	600	4.7
21	Tulsa	1,000	4.4	1,000	3.8	600	5.0
22	New Orleans	....	....	1,000	3.7	600	4.7
23	Denver	*1,000	4.1	*1,000	4.1	600	4.9
24	Albuquerque	1,000	4.3	*600	4.4	600	4.9
25	Seattle-Tacoma	800	5.0	1,000	5.3	800	4.7
26	San Francisco	1,500	6.2	1,500	4.9	1,000	4.4
27	Los Angeles	1,000	5.5	1,500	5.0	1,000	4.4
28	Phoenix	1,000	4.9	*1,200	4.6	600	5.0

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[1] Includes production expenses, fuel, transmission expenses and the fixed charges generally applicable to the region in which the particular plant is located, on production and transmission facilities. Estimates based on large-unit, seasoned plants of 1 to 4 units. Estimates assume no price escalation. Assumed plant factors are 70% for conventional steam plants and 80% for nuclear plants.

*Single unit plant.

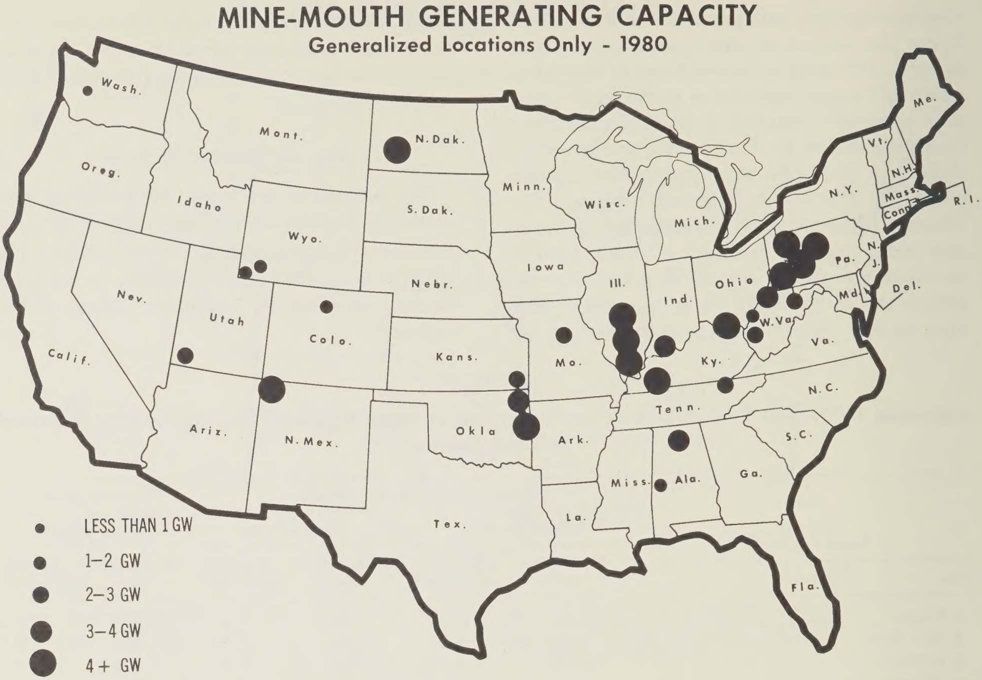
MINE-MOUTH GENERATING CAPACITY
Generalized Locations Only - 1980

FIGURE 118

From the data presented in table 56, it is apparent that nearly 50 percent of the total capacity installed in 1980 will be in thermal plants to be placed in service after 1966. Most of this capacity has been judged to be appropriately supplied from units of 800,000 kilowatts and larger which is evident in examining the summary of projected categories and sizes as presented in table 58. The projection includes some 135 units of 1,000,000 kilowatts and larger (up to 1,500,000 kw) with a total capacity for the nation of 154 million kilowatts. About 40 of these are nuclear power units. Most of the smaller units in the size range below 400,000 kilowatts are accounted for by existing units which will remain in service through 1980 and by some units in the smaller sizes currently on order.

The selection of this high proportion of very large units is consistent, we believe, with the goal of the lowest possible cost of power. A key element in accommodating these large units in our nation's medium and small size systems will be the existence of strong interconnections that will achieve a high degree of interconnection by 1980. However, full coordination between the East and West zones is not a prerequisite to use of these unit sizes because the estimated interconnected capacity of the East zone to serve loads projected for 1980 is 426 gigawatts or about 82 percent of the interconnected capacity of all four sectors. We recognize that lesser degrees of coordination are essential intermediate steps for progressive expansion of coordination limits, but if such intermediate steps were to be regarded as end objectives, the selected unit sizes would be reduced in order to minimize reserve requirements. But these periods for capturing economy from minimized reserves through lesser unit sizes would be brief and opportunities for greater savings in the long run would be lost, unless sizes are determined on the basis of a dynamic integration program.

If systems are to be developed to take maximum advantage of the economies that full coordination can offer in the years ahead, we believe the goal of broad interconnection and coordination must be accepted now. Such coordination will provide the country with transmission interties able to surmount major emergencies and load shifts, and with the flexibility to serve major new loads. In determining whether to strive for this goal, systems cannot overlook for very long the important companion economies of being able to use larger size generating units to meet their loads.

The Pattern of Transmission

Figure 116 depicts a possible pattern of transmission lines for 1980. This pattern includes the relatively few EHV lines now in existence and the large number under construction and planned for the future. In some respects the pattern depicted follows the study programs of the regional advisory committees but it also includes many EHV lines which have not been planned as yet by the industry but are being initially suggested herein as promising possibilities prior to 1980. Since the lines we depict are not based upon detailed engineering studies, figure 116 can be regarded only as a general indication of 1980 requirements. The need for some of the lines will depend on the selection of generating sites—whether at load areas or mine-mouth or at hydroelectric facilities—and on the actual growth and utilization of diversity and numerous other considerations. Each new facility obviously must afford an economic advantage to those who plan and construct it. The pattern is a general program for transmission suited to a broadly coordinated power industry growth and provides a basis for estimating the cost of future EHV transmission.

TABLE 58

Summary of U.S.[1] Generating Capacity—1980

(Gigawatts [2])

	Sectors				
	Northeast	South	North central	West	Total U.S.
Diesel and gas turbine	2. 6	2. 2	1. 9	0. 2	6. 9
Conventional hydro	10. 2	17. 0	4. 1	44. 5	[3] 75. 8
Pumped storage	11. 5	4. 1	2. 4	1. 0	19. 0
Conventional steam:					
0–400	56. 1	56. 0	25. 0	18. 1	155. 2
400–800	14. 1	13. 4	10. 5	2. 2	40. 2
800–1200	36. 1	39. 7	6. 4	6. 3	88. 5
1200 and over	24. 2	22. 9	15. 8	4. 8	67. 7
Subtotal	130. 5	132. 0	57. 7	31. 4	351. 6
Nuclear steam:					
0–400	0. 7	. 0	0. 1	1. 5	2. 3
400–800	2. 6	3. 5	2. 2	2. 2	10. 5
800–1200	16. 0	7. 2	8. 0	8. 5	39. 7
1200 and over	6. 8	2. 7	. 0	7. 7	17. 2
Subtotal	26. 1	13. 4	10. 3	19. 9	69. 7
Total	180. 9	168. 7	76. 4	97. 0	[4] 523. 0

[1] Excludes Alaska and Hawaii.

[2] Millions of Kilowatts.

[3] Dependable capacity, compares with 78 mw of installed capacity.

[4] This capacity plus an estimated 4 gigawatts of power imported from Canada equals the total capacity of 527 gigawatts indicated as required in Table 53.

For better clarity in presentation, some of the 230 kilovolt circuits existing or expected by 1980 are omitted from figure 116. However, in calculating estimated savings referred to in chapter 17, consideration was given to all 230 kilovolt lines as well as other facilities at lower voltages which would be needed to strengthen subtransmission networks.

A review of the reserve and diversity transfers which could be accomplished by such a pattern of interties is set forth below.

Reserve Capacity Transfers

Reserve capacity savings are effected through interconnections and agreements between systems for mutual support and coordination. The savings estimated to be achievable by 1980 can be realized most fully through close coordination in setting reserve levels area by area, and through adequate interconnections between areas. The test of adequate interties to minimize reserves is to be sure that under the most extreme circumstances there exists sufficient transmission capacity to insure that the total reserve required for an area would be available on just as reliable a basis as though all of the reserve was located within the area. Specially provided interconnections may be required between some areas to meet this test.

Many of the transmission lines will be built primarily for purposes other than meeting emergencies such as to permit several systems to share in larger generating units and to take advantage of diversities. At relatively small added cost such lines could be enlarged to supply the reserve deficiencies. Approximate checks on the capacity of transmission lines serving each area to supply supplemental reserve from other areas indicate that transfer capacities ranging from 10 percent to more than 20 percent of the total installed area capacity would be available to supplement area reserves.

Capacity Transfers Resulting From Load Diversity

The general pattern and magnitude of power exchanges needed to make fairly full use of the seasonal, time zone and random diversities anticipated by 1980 are illustrated in figure 115. The principal exchanges of seasonal capacity radiate from the midsouth (areas J and K) which are expected by 1980 to have a summer peak load over 15 gigawatts larger than the winter peak. It is believed the excess capacity in the winter could be exchanged with three eastern areas having winter peaks and excess capacity in the summer in general proportions as follows: Florida Systems, 20 percent, the TVA, 40 percent, and areas in the vicinity of Lake Erie (possibly including Ontario, Canada), 40 percent. As an alternative to transfers with the Lake Erie area, an exchange of about equal magnitude might be made with the Pacific Northwest but the transmission facilities required would be longer and more costly. The magnitude of any of the seasonal exchanges is about 50 percent of the local difference between summer and winter peak loads in the area if capacity savings are fully utilized and shared equally between areas. This is the amount of capacity that must be transmitted between areas in order to make full use of the estimated diversity.

The major capacity movements related to time zone diversity would take place between the Pacific time zone and the Central and Eastern time zones, a time difference of two or three hours. The potential exchanges estimated for 1980 are diagrammed in figure 115. As previously mentioned, effective utilization of time zone diversity will require continuing analyses of detailed load data, especially for peak periods.

Long Distance Interties

There are now some interconnections between systems operating in the West Sector and those in western parts of the North Central and the South Sectors, but these connections do not extend through to the main body of the North Central and South Sectors. A connection between the two separated areas by closure of switching facilities at Fort Peck on a 161 kilovolt line has been tried several times but the tie is inadequate to hold the two major areas in synchronism.

In order to provide heavy-duty interconnections between the East Zone (three eastern sectors) and the West Zone, three major east-west ties plus a northwest to middle south tie have been suggested as illustrating the general pattern and magnitude of interconnections that may be found appropriate by 1980 or before. These potential interties are shown on figure 116. Their approximate lengths, possible voltage levels, and loadings for the principal functions which they would serve are summarized in table 59. These facilities would provide a transfer capability aggregating about 13 gigawatts.

TABLE 59

Potential East-West Zone Interties

Line Route	Line distance (miles)	Possible line voltage (kv)	No. of circuits	Total capacity of circuit (gw)	Loading (gw [1])	
Northern east-west (Lewiston, to Ft. Thompson, S.D.).	1,000	±500 DC	1	3		
Central east-west (San Francisco to Omaha).	1,400	±750 DC	1	3	Net time zone and random diversity [3].	2.8
Southern east-west:					Reserve saving......	3.9
Los Angeles to Four Corners	700	500 AC	1	4	Hydro coordination..	(0.5)[4]
Four Corners to Fort Worth	800	±750 DC				
Northwest to middle south [2] (Lower Columbia R. to Ft. Worth).	1,940	±750 DC	1	3	Seasonal...........	3.0
				13		9.7

[1] Millions of kilowatts.

[2] Alternative to diversity exchange between middle south and northeast.

[3] After allowance for the impact of diversity exchanges on scheduled maintenance.

[4] Offpeak loading

Except for the AC circuit from "4-Corners" [10] to Los Angeles, all four circuits might be either DC or AC, although for these distances and magnitudes of load, direct current would appear to be less expensive than AC lines, considering that no major intermediate interconnections with systems along the routes would be required. Moreover, it is anticipated that improvements and cost reductions in the transmission of direct current will evolve from the growing number of applications which are being planned throughout the world. Terminal equipment which a year or two ago was priced at $30 to $32 per kilowatt is now estimated to cost about $26, based on current design and manufacturing practice. It is not unreasonable to think that application of DC equipment to future wholesale movements of power would permit further reductions in terminal cost of from 10 to 15 percent.

The capacities of the DC circuits shown as possibilities approach 3,000,000 kilowatts per circuit of ± 750 kilovolts with losses averaging 10 percent per 1,000 miles of line. Thus, the four-line pattern would allow for considerable growth in interchange requirements beyond 1980.

The Middle South-Northwest Line

Seasonal diversity exchanges between systems in the Pacific Northwest which have a predominant winter peak and systems in the Middle south area which experience a very high summer peak could call for two-way power flows amounting to as much as 3,000,000 kilowatts. The exchange of this amount of diversity with the Northwest is an alternative to the middle south exchange with the Northeast Sector discussed in part C of this chapter. Latest appraisals indicate that the northeast alternative is probably to be preferred because the same diversity benefits can be obtained with less investment, but neither possibility should be ruled out at this stage.

The Three East-West Lines

As indicated in table 59, the east-west lines would contribute to savings from time zone diversity and reductions in reserve capacity. Also, a tie between the hydroelectric systems of the Columbia River and those of the Missouri River would increase the total firm capability of the systems because of the diversity in occurence of extreme low water cycles between the two river basins. In other words, it would be expected that some energy could be supplied from the Columbia to the Missouri during a period of prolonged low water in the Missouri Basin and likewise from the Missouri Basin to the Columbia. The exchanged energy could be delivered offpeak and in effect be "placed in storage." The magnitude of the firm power increment is estimated to be 400,000 kilowatts and the maximum rate of the offpeak exchange would be in the same order of magnitude. In the aggregate, capacity reductions exceeding 10 million kilowatts by 1980 appear theoretically attainable from these sources.

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[10] The point at which the states of Arizona, Colorado, New Mexico and Utah met, the only such point common to four States in the United States.

The exchanges as projected in table 59 would reduce generating capacity investment for the country as a whole by about $2.0 billion. Utilizing the standard fixed charges developed for the Survey, the annual costs of the facilities would be roughly, $145 million and the annual savings allowing for transmission losses in both capacity and energy, would approach $195 million, resulting in a net saving of about $50 million annually. With a proportionate increase in terminal facilities, these interties would be capable of carrying at least 33 percent more load than assigned in this study.

It would be premature to indicate that the general pattern and analysis of these ties does more than generally identify the type and magnitude of future potential power transfers between these areas—or to conclude that they should or should not be constructed by 1980. Rather, they are presented here as possibilities not to be overlooked and to be carefully reviewed and evaluated from time to time.

This discussion is not to say that a step-by-step approach at some intermediate voltage may not be developed tieing the country east and west. Development of interconnections by stages has been the history of the power industry to date. Some of these steps have already been initiated at least in concept, such as a study of an EHV tie between the Pacific Northwest and the Missouri River Basin system, and a current study of a very large generation source in southern Utah with EHV transmission to southern California and southwest Texas. Also, proposed transmission lines into southeastern Idaho from the Northwest are not very distant from 345-kilovolt lines scheduled to be extended into the Missouri Basin from the east. These several potential programs of transmission are further discussed in later sections of this chapter.

National Defense Considerations

As part of the National Power Survey an appraisal[11] was made of the national defense implications of the power system plans projected in the Survey to 1980. This appraisal identified the most vulnerable elements of these plans in 1970 and in 1980 under a spectrum of attacks appropriate to each. Nuclear weapons effects considered were blast, fire, prompt radiation, and fallout. Coordination Study Area E, consisting of Virginia, North and South Carolina, was analyzed in detail for effect of destruction of generating and transmission capacity in a defense emergency, as well as the adequacy of surviving capacity to serve the surviving load. A more general analysis was made of the power system plans for the nation as a whole for the same time periods.

On the basis of the analytic work contained in the study, the concentration of generating capacity in larger plants does not tend to make power facilities attractive as a primary target nor does it increase the nation's power system vulnerability to collateral damage. Figure 119 shows the percent of capacity represented by "n" largest plants as a function of the number of plants for 1960 and 1970–1980. These data are significant in determining whether the industry is becoming either more vulnerable or more attractive as a primary target in the future. It can readily be seen that in 1980 an enemy would destroy about the same fraction of the total U.S. generating capacity with a given number of weapons as it would today. As the figure illustrates, about 200 power plants now comprise about 50 percent of the generating capacity of the country. However, the 500 largest plants contain only about 65 percent of the total capacity. Destruction of more than one-half of the generating capacity, either now or in 1980, requires ever-increasing numbers of weapons, with marginally decreasing effectiveness of each weapon.

The transmission network is the other component of the power system which is of particular interest in this analysis. The plans projected in the Survey for 1980 provide for a continually in-

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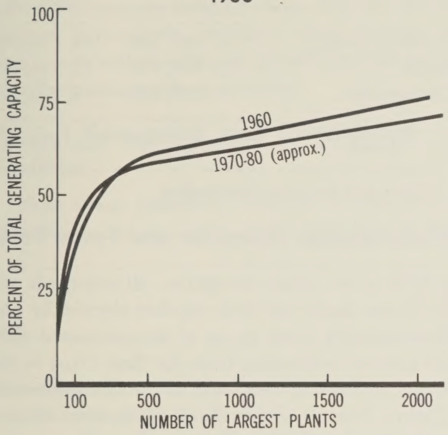
[11] Defense Implications of the National Power Survey, a report by the Research Triangle Institute, Durham, North Carolina, for the Federal Power Commission. The report without its appendices is included in Part II of the Survey.



PERCENT OF TOTAL CAPACITY SUPPLIED BY ANY GIVEN NUMBER OF LARGEST PLANTS
1980

FIGURE 119

creasing interconnection of systems, thus rendering it more difficult to isolate a load from power. The greater interconnection of systems enhances survivability by decreasing the probability that a given service area would be totally without power. However, even today for most areas, interconnections are sufficiently numerous that this eventuality is very improbable.

Location of generating units is perhaps just as important as size, or even more important, from a defense point of view. The pattern of generating stations we project would minimize the number of plants in large metropolitan centers which are themselves prime nuclear targets. The existence of a strong transmission grid thoroughout the country will result in more plants at remote locations and thus they will be less likely to be damaged in the event of a nuclear attack.

The reduction in generating reserve capacity from a current 25 percent to a 1980 value of about 15 percent would seem to be more than compensated by the increased interconnections and increase in total generating capacity (roughly by a factor of 3.5 between now and 1980).

The conclusions derived from our analysis of the defense posture of our power system are:

1. The power industry is now, and will be through 1980, less vulnerable to nuclear attack than the load served.

2. Some relatively inexpensive measures as mentioned below, could be made to reduce the vulnerability of the power industry.

3. For long-term recovery, the reestablishment of fuel supplies and manufacture of new equipment or parts may present the major problems.

At this time, the most desirable measures for reducing the vulnerability of the power industry appear to be:

a. Provision of adequate fallout protection for power plant personnel.

b. More careful consideration to determining the critical parts of the equipment that would be difficult to replace in the post-attack period, but which might be cheaply stocked in advance.

c. In some instances, increasing the inventory of fuel would be feasible as well as practical.

PART C—PATTERN OF POWER SUPPLY—NORTHEAST SECTOR

The Northeast Sector as depicted on figure 110 includes five study areas, namely A, B, C, D, and H. The sector corresponds to the combined areas of FPC power supply regions I and II. While it is the smallest of the four sectors in area, it is one of the largest in total power demand. Noncoincident system peak loads for 1962 were 58,600 megawatts and the projected peak loads for 1970 and 1980 are 95,400 megawatts and 166,500 million kilowatts, respectively. These figures represent approximately 34 percent of the power requirements of the nation in 1980.

Load Distribution

As shown in figure 111, illustrating the general distribution of loads for 1980, the heaviest concentrations of load are in the metropolitan area of New York City, northern New Jersey, and Philadelphia. Principal load concentrations in New England are in Boston, Providence, Springfield, Hartford, and New Haven. Loads are relatively light in the three northern New England states. Heavy loads are also found in the main cities bordering the Great Lakes, principally Buffalo, Cleveland, and Detroit, the heavily industrialized Ohio River Valley, the Pittsburgh-Youngstown area, Cincinnati, and Louisville. A relatively high density of load prevails in the areas between the main load centers of Ohio, Indiana, New York, Eastern Pennsylvania, and New Jersey. Figure 117 illustrates in a general manner the location and magnitudes of the principal load centers throughout the United States.

The five load study areas vary considerably both in geographic area and in size of load. The tabulation below summarizes by areas the actual 1960 and 1962 loads and the estimated loads for 1970 and 1980.

Operating Utilities

There are some 769 individual utility systems operating in the Northeast Sector. The electric power industry serving this sector is composed principally of large investor-owned utilities. Rural electric cooperative systems are numerous in Indiana, Ohio, Kentucky and Pennsylvania. There are relatively few cooperatives in New York, New Jersey, Vermont, New Hampshire, and Maine, and none in Massachusetts, Rhode Island and Connecticut. A large number of municipal systems operate in the Northeast Sector, particularly in the States of Indiana and Ohio. Although some municipal and cooperative systems have their own generation, the greater part of the supply for such systems comes from the larger investor-owned utilities and the Power Authority of the State of New York.

The participation of the several segments of industry in the generation and sale of power in 1962 in the Northeast Sector is summarized below:

	Generated 1,000 Kwh	Retail Sales 1,000 Kwh
Investor-owned	301, 269, 000	283, 744, 000
Public [1]	23, 928, 000	15, 846, 000
Cooperative	860, 000	3, 900, 000
Total	326, 057, 000	303, 490, 000

[1] Municipal and state organizations.

Interconnected Operation and Power Pools

With a few minor exceptions, all systems in the Northeast Sector are tied together electrically and form part of a larger group of interconnected utilities generally extending from the East Coast to the Rocky Mountains designated as the Interconnected Systems Group. Table 60 identifies those systems in the Northeast Sector.

Many groupings of utilities have been formed within the sector for more closely defined exchange of power services between systems. Table 60 summarizes the various pools and interconnected groups which were in operation in 1962. The Hydroelectric Commission of Ontario is interconnected with systems of the Northeast Sector at Detroit, Michigan, and in the vicinity of Niagara Falls and Massena, New York. The transmission network in the Northeast Sector is extensive and sufficiently linked together to permit successful parallel operation. In many cases the ties between systems are

Peak Loads in the Northeast Sector
(Megawatts—Noncoincident)

Area	Actual		Estimated	
	1960	1962	1970	1980
A New England	6, 181	7, 064	11, 410	20, 450
B New York	10, 121	11, 399	18, 080	30, 400
C Pa.-N.J.-Md	12, 004	13, 145	21, 210	37, 550
D Ohio Valley [1]	19, 741	21, 351	36, 180	64, 200
H Lower Michigan	5, 170	5, 623	8, 560	13, 900
Total	53, 217	58, 582	95, 440	166, 500

[1] The AEC Portsmouth gaseous diffusion plant is located in Area D. In 1960 it consumed 17.0 billion kilowatt-hours. The survey estimated an overall 10 percent reduction in diffusion plant loads by 1980. Recently AEC announced about a 40 percent cut overall. At Portsmouth this will be effected by a series of reductions commencing July 1, 1964, and extending to October 1967, at which time the present demand of 1800 megawatts will have been reduced to 700 megawatts.

of limited capacity and are normally used only for power exchange in emergencies. On the other hand, contracts for major power exchanges are in general use among systems in the better integrated pooling arrangements. American Electric Power System, for example, exchanges large amounts of firm power and economy energy with systems in the Northeast and neighboring sectors.

Present Generating and Transmission Facilities

Most power generating facilities in the Northeast Sector are located in close proximity to the load centers. In 1962 coal, oil and gas fired steam-electric plants accounted for over 90 percent of the total generation, hydroelectric power for over nine percent, and diesel and gas turbines for less than one percent. There are many large and small hydroelectric projects in the sector, principally in New England, New York and Pennsylvania, but the bulk of the hydroelectric supply comes from the two major projects of the Power Authority of the State of New York at Niagara Falls and on the St. Lawrence at Massena. These two projects have a total capacity of 3,100 megawatts which provides low cost base load and peaking power.

TABLE 60

Northeast Sector Power Pools

Canadian—Eastern U.S. Interconnection
- New England Pool
    - New England Electric System
    - Eastern Utilities Associates
    - Connecticut Valley Electric Exchange (Convex)
    - Vermont Electric Power Co. (Transmission only)
- New York Pool
    - Upstate Interconnected Systems
        - Niagara Mohawk Power Corp.
        - New York State Electric & Gas Corp.
        - Rochester Gas & Electric Corp.
    - Southeastern New York Power Pool
        - Consolidated Edison Co. of New York
        - Long Island Lighting Company
        - Central Hudson Gas & Electric Corp.
        - Orange & Rockland Utilities, Inc.
    - Michigan—Canadian Group
        - Michigan Pool
            - Consumers Power Company
            - Detroit Edison Company
            - City of Lansing, Michigan
            - City of Detroit, Michigan
            - City of Holland, Michigan
            - City of Wyandotte, Michigan
            - Ford Motor Company
            - Dow Chemical Company
        - Hydro-Electric Power Commission of Ontario (Interconnects with Michigan and New York State)

Interconnected Systems Group
- North Central Area Group

Interconnected Systems Group—Continued
- American Electric Power System
    - Appalachian Power Company
    - Indiana & Michigan Electric Co.
    - Kentucky Power Company
    - Kingsport Utilities, Inc.
    - Ohio Power Co.
    - Wheeling Electric Co.
- Allegheny Power System
    - Monongahela Power Co.
    - Potomac Edison Co.
    - West Penn Power Co.
- The Cincinnati Gas & Electric Co.
- The Cleveland Electric Illuminating Co.
- Columbus & Southern Ohio Electric Co.
- The Dayton Power & Light Co.
- Duquesne Light Co.
- Indianapolis Power & Light Co.
- Kentucky Utilities Co.
- Louisville Gas & Electric Co.
- Northern Indiana Public Service Co.
- Ohio Edison Co. System
- Ohio Valley Electric Corp.
- Public Service Co. of Indiana, Inc.
- Southern Indiana Gas & Electric Co.
- Toledo Edison Co.
- City of Anderson, Indiana
- City of Danville, Virginia
- East Kentucky Rural Electric Coop.
- City of Fort Wayne, Indiana
- City of Hamilton, Ohio
- City of Owensboro, Kentucky
- City of Richmond, Indiana

Pennsylvania—New Jersey—Maryland Interconnection

- Public Service Electric & Gas Company
- Philadelphia Electric Company
  - Atlantic City Electric Company
  - Delaware Power & Light Company
- Pennsylvania Power & Light Co.
  - Luzerne Electric Division
  - The United Gas Improvement Co.
- Baltimore Gas & Electric Company
  - Potomac Electric Power Company
- Pennsylvania Electric Company
- Metropolitan Edison Company
- New Jersey Power & Light Company

With the exception of New England, the Northeast Sector has close access to a broad range of good quality coal. These deposits occur in two principal locations (See figure 27, chapter 3). The largest deposits lie in the Appalachian regions of western Pennsylvania, southeastern Ohio, West Virginia, and Eastern Kentucky. The others border the western end of the sector and occupy part of Western Kentucky, the southeast corner of Indiana and in the North Central Sector, a large south-central section of Illinois. These deposits are abundant and coal is being mined at prices ranging from 13 to 16 cents per million Btu f.o.b. the mines. The distance from coal mines to major load centers in the Northeast Sector, with the exception of New England, rarely exceeds 200 to 250 miles and many of the important centers are within 100 miles. The coal supply sources nearest to New England are in the western part of Pennsylvania, about 500 miles from Boston.

Some natural gas is used for electric power generation in the Northeast Sector. In 1962, gas contributed 4.1 percent of the total fossil-fueled generation in the sector. Gas available for generation is confined to off-peak capacities in long distance pipelines. It does not appear that gas will be a significant source of boiler fuel for new generating capacity to be added in the period after 1970, although its use as a fuel for generation by gas turbines and jet engine gas turbines may expand.

In 1962, fuel oil accounted for 8.1 percent of the total fossil-fueled generation in the sector, most of it confined to New England and seaboard areas. Fuel oil supplies used for generation in these areas are almost wholly from foreign sources and thus are affected by controls on petroleum imports. Fuel oils are not expected to account for more than five percent of the future generation in the Northeast Sector. There are no foreseeable economic trends in the supply of fuel oil which would appear to improve its competitive position with respect to coal.

A number of plants in the Northeast Sector are located in or near the coal fields, but for the most part, mine-mouth generation for long distance movement by wire has not been extensively developed, although several such projects are now under way.

The largest steam-electric units in service in the sector are the 580 megawatts unit in the Tanner's Creek plant and the 450 megawatts units of the Breed and Sporn plants, all of the American Electric Power System. Only about 25 percent of conventional steam-electric generation in the Northeast Sector was produced by units of a size of 200 megawatts or larger.

Nuclear power is now generated in six plants having a total capacity of 675 megawatts, the largest of which is the Indian Point plant of the Consolidated Edison Company of New York. This plant combines base generation of steam from nuclear fuels with oil-fired super heating. Nuclear is credited with 163 megawatts of the total plant output of 275 megawatts.

The highest transmission voltage in operation in 1964 is 345 kilovolts utilized on several systems in New York, West Virginia, Ohio, Indiana, and extending westward into Illinois. The total length of such lines within the sector exceeds 3,000 miles compared with 3,500 miles of 230 kilovolt in operation and nearly 16,000 miles of 138 kilovolt transmission. The principal long distance movements of electric power in the sector are from the New York Power Authority's hydroelectric facilities in northern and western New York to New York City and from the Comerford project in northern New Hampshire to Boston. In Ohio and Indiana, power generated at mine-mouth stations principally along the Ohio River is transmitted over distances up to 350 miles to load centers in those and nearby states. Peaking capacity generally is derived from small and older steam-electric plants, hydroelectric stations and, to a small extent, gas turbines and diesel engines.

Programs for Early Development

The operating utilities in the Northeast Sector have programmed for the next several years the construction of 21 million kilowatts of generating capacity.

In the New England area, a consortium of seven companies has programmed the construction of a 500,000-kilowatt nuclear plant at Haddam Neck, a tidewater location on the lower Connecticut River.

The Consolidated Edison Company of New York is conducting negotiations with Canadian interests for the importation of two million kilowatts of hydroelectric power from a prospective private development at Hamilton Falls in Labrador. In addition the Consolidated Edison Company is planning the early construction of a pumped storage project on the Hudson River near Cornwall with a capacity of 1.8 million kilowatts.

Other major new supplies which are in various stages of planning and construction include the 1.6 million kilowatt Keystone mine-mouth plant to be built in western Pennsylvania by a group of Pennsylvania, New Jersey and Maryland utilities and the 500,000-kilowatt mine-mouth plant at Morgantown, West Virginia of the Allegheny Power System.

Power from these mine-mouth installations will be transmitted to distant markets over 500 kilovolt lines, which will be interconnected at numerous

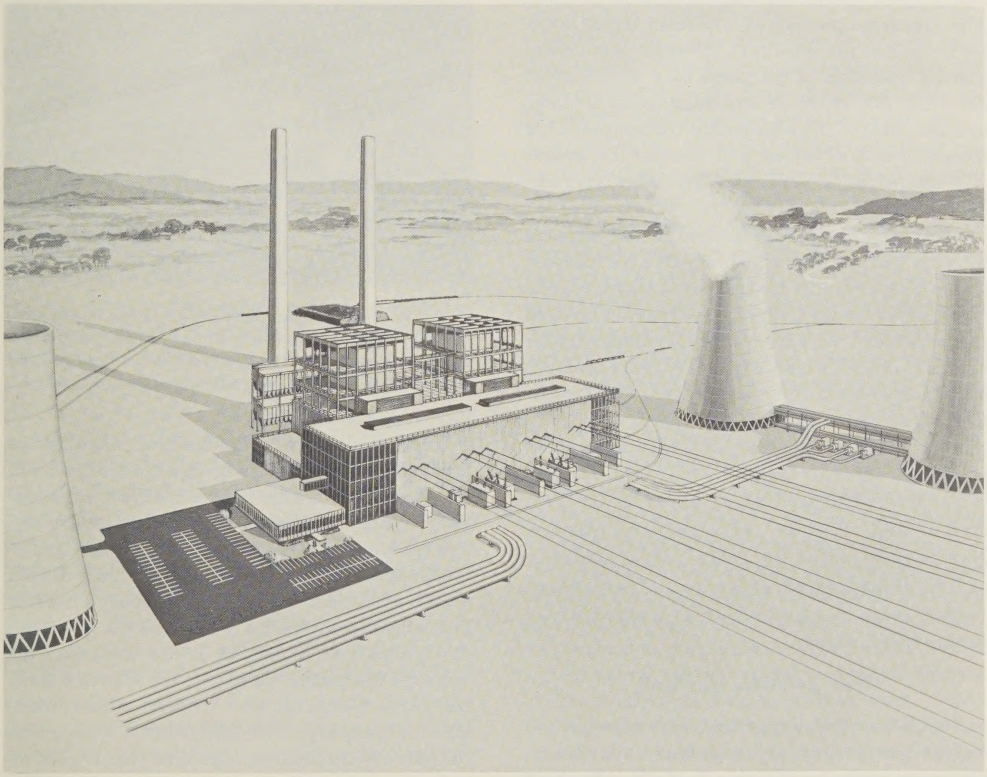


FIGURE 120 *The Keystone Electric Generating Plant located in the coal fields of western Pennsylvania is being jointly developed by a group of investor owned utilities. The two large 800,000 kilowatt units will operate at temperatures of 1000°F and 1000°F reheat and pressure of 3500 lbs. per square inch. Power from the plant will be transmitted about 350 miles on new 500 kv circuits to load centers in eastern Pennsylvania, New Jersey and New York City.*

points with the high tension networks of the many systems in the East. The 500-kilovolt network of the Allegheny Power System will be tied to the 500 kilovolt lines of the Virginia Electric and Power Company and the 345 kilovolt lines of the American Electric Power Company. The last two systems will also tie their high tension lines directly at Roanoke, Virginia.

Plans have been formulated by the American Electric Power System and Buckeye Power, Inc., representing 30 rural electric cooperatives in Ohio, for the construction of a jointly owned 1,230,000-kilowatt plant (2–615,000 kw units) on the Ohio River at Brilliant, Ohio. This is the first project to be planned and built jointly by the private companies and the cooperative group and could provide a useful pattern for other such joint projects. The agreement provides for the financing of Buckeye's share of the investment through commercial sources, operation of the plant by a subsidiary of American Electric Power and transmission of power to substations of the distributing cooperatives over transmission lines owned and operated by subsidiary companies of AEP and five other investor-owned utilities.

Two major nuclear installations now in planning for early construction include the 515,000 kilowatt Oyster-Creek plant of Jersey Central Power & Light Company in Ocean County, New Jersey, scheduled for operation in the winter of 1967, and the 500,000-kilowatt Nine Mile Point Plant of Niagara Mohawk Power Corporation, near Oswego, New York, scheduled for operation in the fall of 1968.

A nuclear power plant of 250 megawatts is being considered for early construction by the Holyoke Water Power Company at the site of its Mt. Tom station near Holyoke, Massachusetts. Another New England utility, the Public Service Company of New Hampshire is considering a 300 megawatt nuclear plant as an alternate to a conventional steam-electric station.

Area A—(New England)

New England at the present time is one of the highest cost electric power areas in the nation. The average retail price of power in New England in 1962 was 29 percent higher than the national average. All fossil fuels are imported into the area since there are no coal, oil, or natural gas resources locally available. Coal is transported to the main coastal generation centers by ocean colliers loading from eastern seaports. These are supplied in turn, in large part, by unit trains from the West Virginia coal fields. The present delivered cost of coal is about 32 cents per million British thermal unit, among the highest for fossil fuels in the United States. As of 1964 reductions in rail transportation rates have been announced which will lower this delivered cost. Oil is received in moderate amounts, mostly from foreign refineries, at a price which approximates the prevailing cost of coal. Utilities recently have entered into long-term contracts with ocean shippers of coal, but the uncertainty of the overseas oil supply has ruled against similar contracts for oil.

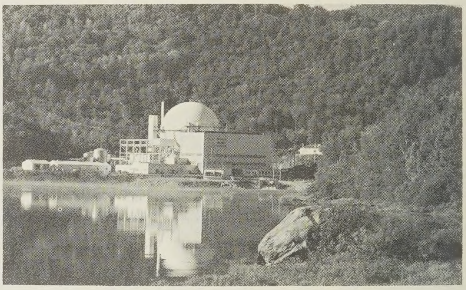


FIGURE 121 *The Yankee Atomic Generating Station, near Rowe, Massachusetts, owned jointly by 10 utilities, began first power production in 1960. This 175,000 kilowatt plant utilizes a pressurized lightwater reactor.*

Electric power systems in the lower New England area—Massachusetts, Rhode Island, and Connecticut—can profit greatly from the further coordination of their enterprises. Such arrangements are now under way. One example is the formation of the Connecticut Valley Electric Exchange (CONVEX) in December 1963, which brought together into a highly coordinated power pool the systems of the Connecticut Light and Power Company, the United Illuminating Company, the Hartford Electric Light Company, and Western Massachusetts Electric Company. It is expected that considerable benefits will accrue from the joint planning of required capacity additions and the coordinated operation of the four systems' generating and transmission facilities. The upper New England states, Vermont, New Hampshire, and Maine, are handicapped by fewer people, smaller loads, and a greater distance to thermal fuel sources. However, as loads in the upper states develop, it might become practical to reduce power costs in the area by retaining for local load service a greater share of the hydroelectric power now generated in the upper states and delivered to the load areas of the lower New England states.

Systems in New Hampshire and Vermont are now rather poorly interconnected. Strengthening of ties is required and would be of value not only for firm power service but for sharing reserves. Further reserve support from the lower states could be adequately supplied via transmission lines which serve for the southward movement of hydroelectric power.

Prospective sources of electric energy other than thermal generation include moderate amounts of hydroelectric power which can be developed in Northern Maine and in the sharing with New York utilities of imports of hydroelectric power from Canada as these become economically feasible. The best remaining site for a major source of hydroelectric power is located on the St. John River in Northern Maine where 475 megawatts of dependable capacity at a load factor of 18 percent could be developed. Passamaquoddy tidal power opportunities are currently being re-examined but it remains to be seen whether there is a way of developing this project which would produce power at a cost as low as can be achieved by the coordinated development of other power sources.

Systems in Maine operate in virtual isolation. The upper St. John's River project could provide energy at reasonable cost in spite of the transmission distance to load centers at Bangor, Augusta, Lewiston, and Portland. A nuclear plant of 500 to 800 megawatt capacity located on the lower Maine or New Hampshire coast would provide an economic and reasonably close source of energy for population and industrial centers in Maine, New Hampshire, and Massachusetts. While the local load is growing, capacity not needed in the upper states could be diverted to help meet the larger needs of eastern Massachusetts. Reserve capacity for Maine loads, during outage of such a nuclear plant, could be supplied through interconnections with the Massachusetts utilities.

Beneficial ties between these upper states and with systems in New York and the Provinces of Quebec and New Brunswick are foreseeable. The present principal tie connecting New York and Vermont delivers firm power from the Power Authority of the State of New York.

There appear to be several alternatives for future power supplies from thermal sources that require continuing evaluation. These include:

1. Generation from large-scale conventional coal-fired steam-electric plants located close to the major load centers of New England and receiving fuel supplies by ocean colliers or by integral train delivery from mines in Pennsylvania.

2. Construction of large-scale, mine-mouth, plants in the coal fields of Western Pennsylvania with transmission of power to New York and New England load centers via 500-kilovolt transmission lines.

3. Construction of large-scale nuclear plants in general proximity to the major load centers or farther north as suggested above.

Water supplies and plant sites are readily available for either fossil-fueled or nuclear-fueled generation along the main rivers of Massachusetts and Connecticut and along the extended coastal area.

Any of these alternatives would offer lower cost power than now available from the plants in operation in the area. Through future economies fuel cost at major New England load centers may approach 28 cents per million Btu compared with current costs of 32 cents. The combined effect of this saving and of other economies attainable with large plants would result in estimated bulk power costs generated at load centers less than 5.5 mills per kilowatt-hour as contrasted with comparable average costs today which are roughly 50 percent higher. The best New England costs today are just under eight mills per kilowatt-hour.

The alternative of an EHV transmission line from the Pennsylvania coal fields to New York and New England, offers several important advantages if economically feasible for some of the needed power supply. The line would be a strong east-west component in the transmission network and, at a nominal increase in cost, these circuits could also serve for emergency reserve support and minor diversity exchanges between systems in these areas. Additionally, this alternative reduces air pollution and alleviates the more costly siting problems that attend construction of conventional plants near large load centers.

The load density in the three lower New England states in 1980 will average 1200 kilowatts of peak load per square mile. The three-state area has a total east-west length, excluding extremities, of 140 miles; and a north-south length of a little over 100 miles. If local generation centers are developed, using either conventional or nuclear steam-electric stations, economies can be achieved through the use of large-sized units. With plants located in the area of the planned Haddam Neck nuclear plant on the lower Connecticut River some 25 miles down river from Hartford, on the waterfront in the vicinities of Providence and Boston or at other locations, the great bulk of the output would be delivered to load centers over transmission distances of less than 50 miles. With indicated advances in design, this plan may prove to be more economical for some segments of the load than the other alternatives. Annual load growth in lower New England by 1970 will approach 625,000 kilowatts. This growth rate, plus the desirability of interconnections with Area B for short-term interchanges of excess capacity, indicates the possibility that the New England utilities on a coordinated basis could utilize units of 1,000,000 kilowatt capacity by 1970, and larger in the following decade.

A 345-kilovolt transmission line is under construction from lower New York to central points in Connecticut and Massachusetts. Such lines for the relatively short distances involved can carry loads of 500,000 to 600,000 kilowatts and can serve the area adequately through 1980. In consideration of a general power supply pattern for 1980 which may include delivery of 1,000,000 kilowatts to New England from mine-mouth plants in Western Pennsylvania, another 1,000,000 kilowatts from hydro capacity in Canada, and the requirements for diversity and reserve support with other areas, the required transmission interconnection capacity between New York and New England could be 4,000,000 kilowatts or more by 1980. Thus with the help of some lower voltage ties which now exist and may continue to be augmented, it appears that not less than four 345 kilovolt-lines will be needed for adequately coordinated operation by 1980.

The several principal generating centers depicted in the general pattern of Figure 116 are contemplated as being suitable for nuclear development, conventional thermal generation, or some of each. The competing circumstances between types and among methods of fuel or energy delivery are subject to continuous variations and study; hence, the patterns which are summarized for Area A in Table 61 represent only one of the many variations that could prove desirable. However, the pattern does serve to focus on the major opportunities for economic improvement through coordinated planning and operation on a region-wide scale.

Areas B and C—(New York, Pennsylvania, New Jersey, Delaware, and Maryland)

The outlook for continued improvement in the cost of supplying electric power to these areas is highly favorable. The eastern coastal area from New York City to Washington, D.C., has a greater density of population and electric load than anywhere else in the United States. Total electric loads in Areas B and C may reach about 68,000 megawatts by 1980.

The opportunities for economical generation cover several closely competitive alternatives—mine-mouth generation in western Pennsylvania and West Virginia with transmission of output via EHV lines for average distances of 300 to 500 miles to eastern load centers; transportation of coal by unit trains or pipeline to load center plants; nuclear generation along the coast or along the south shores of Lakes Erie and Ontario; and importation of some hydroelectric power from Canadian resources. Coal by wire from generation by mine-mouth plants, generation near load centers with coal delivered by modern unitized train, and large-scale nuclear generation should be closely competitive for eastern loads. With the development of mine-mouth plants using units of 800,000 to 1,500,000 kilowatts, the cost of power at eastern cities might be in the range of 4.5 to 5.0 mills per kilowatt-hour. Large nuclear plants in the early 1970's under second and third cycle fuel cores may be able to supply energy in this same general cost range. The situation presents ideal opportunities for extensive coordination among the utilities serving the area in joint planning, construction and operation.

Most systems in study Area C are well interconnected now. The PJM Pool (Systems in Pennsylvania, New Jersey, and Maryland) (see Table 60) operates under a central system of load dispatching and obtains the benefits of numerous types of power exchanges among member systems. In 1963, three companies of the pool announced plans for the joint construction and operation of the Keystone Electric Generating Station in the coal fields of western Pennsylvania. Power from the station's two units of 800,000 kilowatt capacity each will be transmitted at 500 kilovolts to Philadelphia and to the vicinity of New York City. Joint ventures of this kind or large plants located nearer load, delivering power to multiple load centers, might be repeated many times and expanded in scope in meeting the area's power demands in 1980.

At the present time, power supplies in New York State (Area B) are derived principally from two sources—fossil fuel-fired steam-electric plants in and around the major load centers and hydroelectric power largely from the recently developed major hydroelectric plants of the Power Authority of the State of New York at Niagara Falls and on the St. Lawrence River near Massena, New York. These two hydro plants have a total capacity of 3,100,000 kilowatts which is transmitted to mid-state and down-state load centers by a network of 345 kilovolts and lower voltage lines. As future loads in upstate New York increase, a greater portion of the output of these plants could be retained for upstate needs. Thus, some capacity on the EHV grid would be made available for exchanging reserve support between the upper and lower areas.

Electric power for the City of New York is now largely generated by coal and oil fired steam-electric stations located within the metropolitan limits of the city. Unit sizes range from 20 to 400 megawatts, with ages of 1 to 50 years. Several of the plants are small, old and relatively inefficient. Plans are underway for the improvement of the system's economy.

A 1,000,000 kilowatt unit, the first unit of this size to be manufactured will be placed in operation by the Consolidated Edison Company in its Ravenswood plant in 1965. In addition the company has applied to the Federal Power Commission for a license to construct a 1,800,000 kilowatts pumped storage project on the Hudson River near Cornwall and is negotating with Canadian interests for a long-term purchase of 2,000,000 kilowatts at high load factor to be transmitted from the Hamilton River project in Labrador. The transmission from Canada to New York City may utilize extra high voltage direct current. Other resources which are considered economically competitive for serving loads in Area B to meet the 1980 requirements include large-scale nuclear generation on Lake Erie and nuclear or fossil-fired steam generation in the vicinity of Albany.

Considerable pumped-storage capacity for peak service is now under construction or in the planning and investigation stage in Area C, favored as it is by rugged terrain and low cost pumping energy. Among these projects are Yards Creek with 330,000 kilowatts; Muddy Run on the Susquehanna River with a planned capacity of 800,000 kilowatts; Kinzua on the Allegheny River with 325,000 kilowatts; Tocks Island on the Delaware River with 900,000 kilowatts; and many others. The peaking capacity of the Conowingo station, a conventional peaking hydro installation on the Susquehanna River, is being increased to 474,500 kilowatts by the addition of four units.

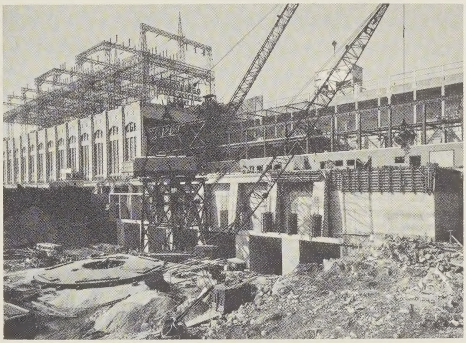


Figure 122 *FPC license of the Conowingo Project on the Susquehanna River was amended in 1961 to provide for the addition of four 55,620 kilowatt units. When the planned expansion is completed, the plant will have a total capacity of 474,500 kilowatts. The plant provides low cost peaking power for a group of utilities whose supply of firm power is derived mainly from steam-electric generation. During low water months, the Conowingo plant factor may be as low as 4 percent.*

Many systems in the area adopted industrial gas turbine and aircraft jet engine gas turbine driven generators for peak service. A jet engine unit of 121,000 kilowatts is scheduled for installation late in 1965 at the Sewaren station of Public Service Electric & Gas Company and two smaller units are being installed by the Delaware Power and Light Company.

The present transmission grid in Areas B and C, with the exception of 345 kilovolt lines serving hydroelectric projects in upper New York, generally follows a graduated pattern of 115, 230, and 500 kilovolts. The doubling of voltage increases the line carrying capacity about four times. Heavy load growth and the opportunities to economize through increased unit size and mine-mouth locations have precipitated a relatively quick transition from the 115 kilovolt to the 500 kilovolt level.

The 500 kilovolt network depicted in Figure 116 is mainly based on the advanced planning of the utilities in the area which was outlined by the Regional Advisory Committee of the National Power Survey. It appears to represent a forward and coordinated approach toward achieving adequate line capacity for transmitting firm power from generating centers to load and for exchanges between systems for reserve support and other transfers. The transmission pattern has been arranged to provide interconnections between mine-mouth plants in western Pennsylvania serving loads to the east with plants serving loads in Ohio, Indiana, and Michigan. These interconnections will effectively tie together the two most heavily loaded areas in the nation and permit the transfer of firm, diversity, reserve power, and economy energy.

Areas D and H—(Indiana, Ohio, West Virginia, Kentucky, and Michigan)

Concentrations of population and of industrial development in Areas D and H, particularly in Ohio, Indiana and southern section of Michigan, create heavy demands for electric energy, particularly along the Ohio River and the shores of the Great Lakes.

Area D, which closely approximates the four-state area of Indiana, Ohio, West Virginia and Kentucky, holds a particularly favorable position with relation to fuel resources. Large bituminous coal deposits of good quality are available in the eastern, southern and western sections of the area. Much of the generation in the area is supplied by large plants located along the Ohio River and its principal tributaries at locations close to fuel sources.

A large part of new generation required for loads to 1980 in Areas D and H, perhaps as much as 80 percent, may come from large bituminous coal-fired, steam-electric plants in the coal fields in western Pennsylvania, West Virginia, Ohio, eastern and western Kentucky, southern Illinois and Indiana, and at locations near the load centers of Detroit, Saginaw, Jackson, Gary, Toledo, and Cleveland.

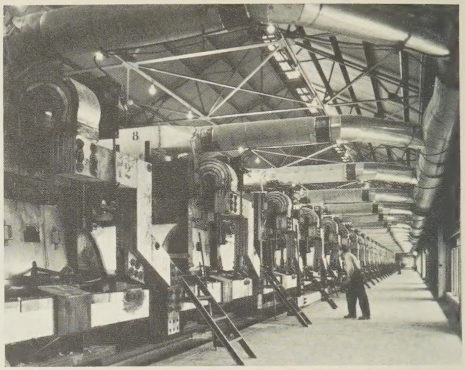


FIGURE 123 *Aluminum is being separated from alumina in this modern potline of the Aluminum Company of America at Massena, N.Y. The potman breaks the crust of alumina which forms on the surface of the bath. The multiple strap-like members are aluminum busbars, which conduct electricity to the reduction pot. Their size is dictated by heavy power requirements at low voltage. The basic separation process is the same as first used over 75 years ago.*

Nuclear generation may become competitive with conventional generation in the early 1970's for locations in Michigan and northern Ohio. The shores of Lake Michigan and Lake Erie offer cooling water and access to water transportation of large nuclear plant components. The location of large plants in the central sections of Ohio and Indiana would require construction of evaporative cooling facilities because of limited cooling water supplies. Even so, properly placed and sized facilities served by unit train coal deliveries or by coal slurry pipelines would be competitive with alternative mine-mouth or nuclear plants. In the 1975–1980 period high load factor energy from coal-fired plants should be available at Ohio River load centers at costs of about 3.8 mills per kilowatt-hour and in the Cleveland, Toledo and Michigan load centers at about 4.5 mills per kilowatt-hour. Costs from large nuclear plants serving Toledo, Detroit and load areas in western Michigan may be as low as 3.8 mills per kilowatt-hour.

Under arrangements for staggering construction among the utilities, or between groups of utilities, the largest economical generating units can be installed by all utilities throughout the area. This is apparent from the annual requirements of new capacity for Area D in the 1970's which will average nearly 3,000,000 kilowatts per year.

Peaking capacity will be provided from older steam plants, a planned pumped storage development near Ludington, Michigan with an aggregate capacity of about 1,500,000 kilowatts and from new hydroelectric plants at various locations possibly aggregating about the same capacity.

Present transmission facilities in Area D constitute probably the strongest network in any of the 16 load study areas. The basic underlying grid consists principally of 138-kilovolt transmission lines. A stronger overlying 345 kilovolt grid is developing and as indicated in Figure 116, is expected to become the principal grid in the 1970's. The addition of a third level of transmission voltage in the range of 700 kilovolts probably will be needed at least in the Indiana area, in the late 1970's. Heavy concentrations of load and growing congestion in the expanding industrial centers will be strong factors in determining the long-range economy of a 700-kilovolt network from the standpoint of higher line capacities and lesser right-of-way requirements. In addition to serving the movement of power from centralized generating stations to load areas, the heavier network would facilitate the staggered construction and sharing of large units.

Part of the capacity of the main east-west 700-kilovolt lines may be employed for seasonal diversity exchanges between Ohio and Pennsylvania utilities, which have winter peaks, and mid-south and Illinois utilities having summer peaks. These transfers conceivably could be facilitated by seasonally redirecting some of the output of mine-mouth plants in southern Illinois and Indiana.

The Hydro-Electric Power Commission of Ontario reports a peak demand in 1963 of 6,797,000 kilowatts and an excess of winter peak over summer peak demands of about 500,000 kilowatts. It seems likely that about one-third of the unused summer capacity could be coupled with excess summer capacity from Ohio and Pennsylvania as described above and moved to the mid south in return for northward movements of capacity to assist in meeting winter peaks. However, major utility systems in Michigan have failed to take advantage of opportunities to interconnect with major systems to the south. The 700 kilovolt tie with Michigan utilities in the lower part of the state would facilitate this two-way transfer of capacity. If it be assumed that the magnitude of the present Ontario summer-winter difference will triple by 1980, power movements passing through interconnections in the vicinity of Detroit by reason of diversity might then be on the order of 500,000 kilowatts. This would be in addition to an existing exchange of about 500,000 kilowatts by reason of coordinating hydro and steam generation. At the present time, four 230 kilovolt circuits in Ontario extend between the boundary connections near Detroit, eastward for 220 miles north of Lake Erie to Canadian hydroelectric resources at Niagara Falls with limited connections to New York utilities. Strengthening of these interconnections and allowing an unrestricted flow to take place along this northern route under emergency and planned diversity exchanges would complement the operating stability and economy of both U.S. and Canadian systems. Most of the major electric systems in Area D mutually contribute a large measure of reserve support through the gen-

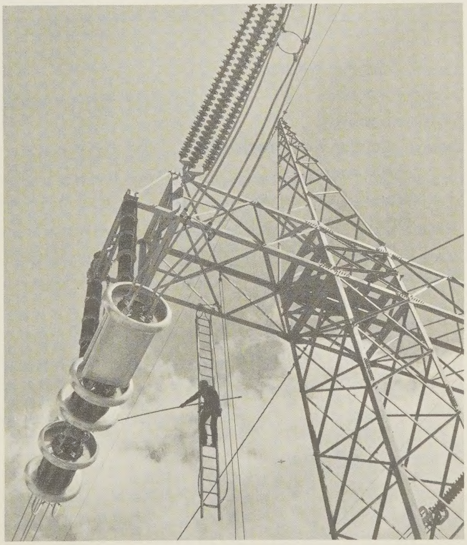


FIGURE 124 *Workmen adjust tuning device on 750,000 volts Apple Grove outdoor test project of American Electric Power System and Westinghouse Electric Corporation to permit tests of radio interference on EHV designs.*

erally strong interconnections of systems. Expansion of the grid to achieve the general pattern depicted for 1980 will augment the opportunity for further support internally and externally to all bordering areas. This opportunity of course, requires detailed engineering studies to test its feasibility. In all probability initial ties between Ohio and Michigan will be at 345 kilovolts. The interconnection of Michigan utilities—thus far without any interstate ties except through Canada—on the 700 kilovolt loop as indicated in Figure 116 and strengthening of interconnections with Canada at Detroit and at Niagara Falls will greatly improve the transmission networks of the Michigan utilities, the connecting utilities in Canada and the entire power economy in Canada and the United States bordering Lake Erie.

Summary for Northeast Sector

Table 61 summarizes the sources of generation by general categories and for thermal plants by groups of unit sizes which have been included in the study of the general pattern for meeting the 1980 loads in the Northeast Sector. The table includes existing generation which will be retained for service through 1980. The general locations of new facilities assumed for 1980 are depicted on Figure 116.

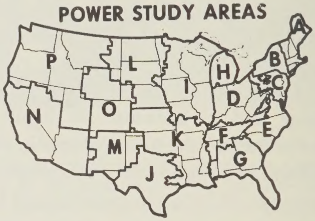


TABLE 61

Northeast Sector—1980 Capacity Supply in Gigawatts

Source of capacity	Area A	Area B	Area C	Area D	Area H	NE Sector
Diesel and gas turbine	0.7	0.5	0.6	0.6	0.2	2.6
Hydroelectric	1.8	4.0	1.2	3.0	0.2	10.2
Pumped storage	1.1	2.6	4.3	2.0	1.5	11.5
Steam-electric fossil fueled:						
0–400 mw units	4.8	7.1	13.4	24.2	6.6	[1] 56.1
400–800 mw units	1.0	2.6	2.8	5.9	1.8	14.1
800–1,200 mw units	5.6	4.8	7.3	15.7	2.7	36.1
1,200 and over mw units	2.4	2.6	5.2	14.0	0	24.2
Nuclear:						
0–400 mw units	0.1	0.3	0.1	0	0.2	.7
400–800 mw units	2.0	0	0.6	0	0	2.6
800–1,200 mw units	3.0	7.0	3.0	1.0	2.0	16.0
1,200 and over mw units	0	0	2.8	4.0	0	6.8
Total capacity	22.5	31.5	41.3	70.4	15.2	180.9
Percent distribution:						
Diesel and gas turbine	3.1	1.6	1.5	0.9	1.3	1.4
Hydroelectric	8.0	12.7	2.9	4.3	1.3	5.6
Pumped storage	4.9	8.2	10.4	2.8	9.9	6.4
Steam-electric fossil fueled	61.3	54.3	69.5	84.9	73.0	72.2
Nuclear	22.7	23.2	15.7	7.1	14.5	14.4

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[1] This consists of 501 units below 200 mw totaling 37.6 gw of which 455 units totaling 33.0 gw were in service in 1960; and 70 units between 200–400 mw totaling 18.5 gw of which 46 totaling 11.7 gw were in service in 1960.

PART D—PATTERN OF POWER SUPPLY—SOUTH SECTOR

The South Sector as outlined in figure 110 includes Study Area E, F, G, J, K, and M. The sector extends from the Atlantic Ocean on the east to the western border of the State of New Mexico. From south to north, the sector extends from the Mexican Border and the Gulf of Mexico to an irregular mid-continent line extending through northern Virginia, southern Kentucky, southern Missouri, and most of Kansas. The South Sector comprises FPC Supply regions III and V. It includes all or parts of 17 states. The sum of system non-coincidental peak loads for 1962 in the South Sector was 50.6 million kilowatts, and the projections for 1970 and 1980 are 90.1 million kilowatts and 168 million kilowatts, respectively. This constitutes about 34 percent of the power requirements for the nation in 1980, as compared to approximately 32 percent at present. Load growth by study areas is summarized as follows:

Load Growth in the South Sector in Megawatts

	Area	1960	1962	1970	1980
E	Carolinas-Virginia	6, 807	7, 977	13, 850	26, 780
F	Tennessee Valley	10, 732	12, 198	18, 070	29, 630
G	Southeastern	8, 836	10, 769	21, 510	42, 530
J	Texas Area	6, 665	8, 070	14, 960	27, 270
K	Middle South Area	8, 354	10, 050	18, 590	35, 900
M	New Mexico and Panhandle	1, 333	1, 545	3, 100	5, 870
	Total	42, 727	50, 609	90, 080	167, 980

Load Distribution

As indicated on figure 117, most of the principal load centers are of moderate size and are broadly distributed throughout the sector; they include, among others, the Arlington-Alexandria, the Norfolk-Hampton and Richmond areas of Virginia; Charlotte-Gastonia and Winston-Salem areas of North Carolina; Greenville and Charleston, South Carolina; Atlanta and Augusta, Georgia; Miami, St. Petersburg-Tampa and Jacksonville, Florida; Knoxville-Oak Ridge, Chattanooga, Nashville and Memphis, Tennessee; Paducah, Kentucky; Jackson, Mississippi; Little Rock, Arkansas; Wichita, Kansas; Oklahoma City and Tulsa, Oklahoma; New Orleans and Shreveport, Louisiana; and Dallas-Fort Worth, Houston and San Antonio areas of Texas. The only general areas of light loading as depicted in figure 111 are the coastal plains regions of North and South Carolina, Georgia and Alabama, the western portions of Texas, Oklahoma, and Kansas and the State of New Mexico.

Operating Utilities

The South Sector is served by a complex of investor-owned, municipal, rural electric cooperative, federal and state and county sponsored electric utility systems. The largest segment of the power industry in the South Sector, in terms of ownership, is made up of 48 class A & B investor-owned utilities.

Among the largest of this group are such companies as Virginia Electric & Power Company, Duke Power Company, Carolina Power & Light Company, Georgia Power Company, Florida Power & Light Company, Florida Power Corporation, Alabama Power Company, Arkansas Power & Light Company, Mississippi Power & Light Company, Louisiana Power & Light Company, Oklahoma Gas and Electric Company, Kansas Gas and Electric Company, Gulf States Utilities Company, Houston Lighting & Power Company, Texas Electric Service Company, Texas Power & Light Company and Central Power and Light Company. Many of these systems are taking part in major advances toward more extensive coordination. The participation of these utilities in various pooling arrangements are summarized later in this section.

The largest utility in the sector (and in the country) is the Tennessee Valley Authority which supplies the electric requirements for nearly all of Tennessee, northern Alabama, northeast Mississippi and small parts of Kentucky, North Carolina, Georgia and Virginia, within or bordering the Tennessee River Basin. With few exceptions, all towns and cities in the TVA service area have municipal systems which purchase their entire requirements from TVA. Most of the smaller communities are served by cooperative systems which distribute TVA power, but many of the municipal systems serve extensive rural areas in addition to the urban centers. The 1962 peak load on the TVA system was 11,677,000 kilowatts, about 27 percent of which was developed from hydroelectric installations, and the remainder by large coal-fired steam-electric plants.

The Southeastern Power Administration (SEPA) of the Department of Interior markets the power generated from eight federally-owned hydroelectric plants having a total installed capacity of 1,082,000 kilowatts. Marketing is direct to utilities or through wheeling contracts with other utilities, and most of the power is sold to preference customers. SEPA sells to TVA the entire output of five other federally-owned hydroelectric plants, all in the Cumberland River Basin having a total installed capacity of 595,000 kilowatts. SEPA has no transmission facilities of its own.

The Southwestern Power Administration of the Department of Interior markets the power generated from nine federally-owned hydroelectric plants having a total installed capacity of 791,000 kilowatts. The power is marketed over a Federal transmission system and through wheeling contracts with other utilities including REA financed generation and transmission (G&T) cooperatives.

In the South Sector there are 29 large cooperatives (net energy for system of more than 100 million kilowatt-hours annually) of which 13 are G&T cooperatives. In addition, there are 384 small cooperatives. Twenty-one of the large cooperatives, and thirty others, are in the TVA area. While the cooperatives in the South Sector have a total installed capacity of 357,211 kilowatts, a majority of the cooperatives depend on other utilities for supplying their power requirements.

The larger municipal systems in the South Sector include those serving Springfield, Missouri; North Little Rock, Arkansas; Huntsville, Alabama; Memphis, Knoxville, Chattanooga, and Nashville, Tennessee; Jacksonville, Orlando, Lakeland, and Tallahassee, Florida; High Point and Fayetteville, North Carolina; and Austin and San Antonio, Texas. In all, there are 59 large (including 39 served by TVA) and 689 small municipal systems in the South Sector. They have a total installed capacity of 4,421,079 kilowatts.

There are seventeen state or county sponsored electric utilities in the South Sector. These utilities have a total installed capacity of 771,464 kilowatts.

In 1962, private utilities supplied 60.1 percent of the electric energy delivered to ultimate consumers; cooperatives supplied 6.9 percent; Federal systems supplied 16.8 percent and other public systems supplied 16.2 percent.

Interconnected Operation and Power Pools

All of the utilities in the South Sector except those in Study Areas J and M operate in parallel and are part of the larger Interconnected Systems Group which spans most of the eastern half of the United States. Within this sector the principal operating pools and groups are the Carolinas-Virginia Group, the Tennessee Valley Authority-Aluminum Company of America pool, the Southern-Savannah Group, the Florida Group and the Southwest Power Pool (each a part of the Interconnected Systems). The Texas Interconnected Systems and the Rio Grande-New Mexico pool are not at present operating in synchronism with the rest of the sector or the Interconnected Systems Group. Table 62 lists the members of these pools.

The westernmost group known as the New Mexico Power Pool was established in 1951. This pool, tied to Arizona Public Service Company system in May 1963 by a 230-kilovolt line from the latter's Four Corners steam-electric plant to Albuquerque, New Mexico, now operates in parallel with the Pacific Southwest.

The Southwest Power Pool, an association formed during World War II, is comprised of 15 electric systems operating in Kansas, southern Missouri, Arkansas, Oklahoma, Louisiana, east Texas and western Mississippi. It maintains a central office for evaluation of power supplies and requirements with particular emphasis on reserve. All interchanges among pool members are based on separate agreements made among the parties.

The Southern Company System is a holding company for four large operating companies in Georgia, Alabama, Mississippi, and Florida and for one generating company in Alabama. The operations of the several companies are controlled by a central power coördinating office utilizing analog computing control equipment for selecting the most economical loading of available steam-electric generating equipment. Similar pooling arrangements have been initiated among three Florida companies, namely, Florida Power Corporation, Florida Power & Light Company and Tampa Electric Company, which are interconnected among themselves and with certain municipal systems, as shown in table 62. In Virginia and the Carolinas, a power pool agreement has been in effect for a few years which has fostered various exchange agreement between the signatory parties consisting of the Virginia Electric and Power Company, Carolina Power & Light Company, Duke Power Company, and South Carolina Electric & Gas Company.

TABLE 62

South Sector Power Pools

Interconnected Systems Group

- Carolinas-Virginia Group:
  - Virginia Elec. & Pwr. Co.
  - Carolina Pwr. & Lt. Co.
  - Duke Pwr. Co.
  - S. Carolina Elec. & Gas. Co.
  - Yadkin, Inc.
  - Lockhart Pwr. Co.
  - S. Carolina Pub. Serv. Auth.
  - Southeastern Pwr. Admn.
  - Greenwood County Pwr. Comm.
- Tennessee Valley Authority:
  - Plus ALCOA projects in Little Tennessee River Basin and Southeastern Power Adm. (marketing for Corps of Engineers projects in Cumberland River Basin)
- Southern-Savannah Group:
  - Southern Company System:
    - Alabama Pwr. Co.
    - Georgia Pwr. Co.
    - Gulf Pwr. Co.
    - Mississippi Pwr. Co.
    - Southern Elec. Generating Co.
  - Savannah Elec. & Pwr. Co.
  - Southeastern Pwr. Admn.
- Florida Group:
  - Florida Pwr. Corp.
  - Tampa Elec. Co.
  - Florida Pwr. & Lt. Co.
  - Southeastern Pwr. Admn.
  - City of Orlando
  - City of Jacksonville
- Southwest Power Pool:
  - Arkansas-Missouri Pwr. Co.
  - Missouri Utilities Co.
  - Missouri Pub. Serv. Co.
  - Kansas Gas & Elec. Co.
  - Empire Dist. Elec. Co.
  - Central Louisiana Elec. Co.
  - Gulf States Utilities Co.
  - Oklahoma Gas & Elec. Co.
  - Southwestern Elec. Pwr. Co.
  - Western Lt. & Telephone Co.
  - Pub. Serv. Co. of Oklahoma
  - Middle South Utilities Pwr. Pool:
    - Arkansas Pwr. & Lt. Co.
    - Louisiana Pwr. & Lt. Co.
    - Mississippi Pwr. & Lt. Co.
    - New Orleans Pub. Serv., Inc.
  - Southwestern Pwr. Admn.
  - City of Springfield, Mo.
  - Central Kansas Pwr. Co.
  - Kansas Power & Light Co.
  - Grand River Dam Auth.
  - Associated Elec. Coop., Inc.:
    - Northwestern Elec. Coop.
    - Central Elec. Pwr. Coop.
    - Northeast Mo. Elec. Pwr. Coop.
    - KAMO Elec. Pwr. Coop.
    - Sho-Me Pwr. Corp.
    - M & A Elec. Pwr. Coop.

Texas Interconnection

- North Texas Interconnected Systems:
  - Brazos Electric Power Cooperative
  - Southwestern Pwr. Admn.
  - Brazos River Auth.
  - Community Pub. Serv. Co.
  - Texas Power & Lt. Co.
  - West Texas Utilities Co.
  - Texas Utilities System:
    - Texas Elec. Serv. Co.
    - Dallas Pwr. & Lt. Co.

South Texas Interconnected Systems:
- Central Pwr. & Lt. Co.
- Houston Lighting & Pwr. Co.
- Community Pub. Serv. (South Div.)
- City of Austin
- San Antonio Pub. Serv. Bd.
- Lower Colorado River Auth.

Northwest Texas-Eastern New Mexico

Southwestern Pub. Serv. Co.
New Mexico Elec. Serv. Co.

Rio Grande-New Mexico

El Paso Elec. Co.
Community Pub. Serv. Co.
Pub. Serv. Co. of New Mexico
Plains Elec. Generating & Transmission Coop.
U.S. Bureau of Reclamation

Present Generating and Transmission Facilities

About 87 percent of the present supply of electric energy in the South Sector comes from conventional steam-electric power plants. Most of the remaining generation is supplied from hydroelectric resources and much of this is from the federally owned and operated projects of the TVA and from the federally owned projects whose output is marketed by the Southeastern and Southwestern Power Administrations of the Department of Interior. Some 133 privately-owned hydroelectric projects of various sizes are located throughout the area. There is only one nuclear plant in operation in the South Sector and it has a capacity of only 17,000 kilowatts.

The principal fuel sources for steam-electric generation are coal in the eastern part and natural gas in the western part of the sector. While coal is used to some extent in Florida the principal fuels in that state are oil and natural gas. Most of the steam-electric plants in the southeast are fired with coal transported mainly by rail from coal fields in West Virginia, Alabama, Kentucky, Tennessee, and southern Illinois, while those in the southwest are fired primarily with natural gas. Most of the steam-electric plants are located in the vicinity of the load centers. Condenser cooling water for plants in the east is obtained from stream flow or sea water while plants in the west depend mainly on artificial reservoirs and cooling towers.

Coal deposits known to be economically workable in this sector are located in Arkansas, Oklahoma, Kansas, Missouri, Kentucky, Tennessee, Alabama, and in the northwest corner of New Mexico. Large reserves of lignite are available in central and east Texas.

In 1964, the largest mine-mouth plant, as well as the plant with the largest generating units in operation in this sector (and in the U.S. as a whole), is the Paradise Plant of TVA. It has two generating units of 650 megawatts each, with space for two additional units of similar or larger size. The coal is produced at an adjoining mine which uses stripping equipment of record size. Coal production and use at Paradise is expected to exceed 4 million tons a year. The price of the coal, delivered to the plant in 100-ton trucks, is 12.5 to 14.0 cents per million British thermal units, perhaps the lowest delivered cost in the country.

The broad and scattered distribution of load centers, mostly of small to moderate size, and the intermingling of coal areas and load centers in much of the sector, in combination with a large number of diversely constituted electric systems account for the widely distributed locations of steam-electric generating plants, resulting in construction of the entire range in size of generating units from very small to very large. In 1963 the largest generating units in service among the systems ranged from 650 megawatts of the Tennessee Valley Authority, 400 megawatts of Texas Electric Service Company, 285 megawatts of Florida Power and Light Company, 248 megawatts of Georgia Power Company, 234 megawatts of Oklahoma Gas and Electric Company, 227 megawatts of New Orleans Public Service, Incorporated, to 34 megawatts of the Brazos Electric Power Cooperative.

The great majority of principal transmission lines of electric systems in the South Sector operate at 161, 138 or 110 kilovolts; yet there is a considerable amount of 220 kilovolt transmission scattered throughout the area. A section of 345 kilovolt line was placed in service in 1964 connecting The Texas Utilities System Companies and Houston Lighting and Power Company. Interconnections between main systems in each of the study areas are generally available with reasonable adequacy for the extent of coordination generally practiced within the individual areas. However, operating connections between several study areas are fairly limited; particularly so between Areas J (Texas) and K (Middle South Area). Area M (New Mexico and Panhandle) is interconnected at low voltage with Area J (Texas) and at 230 kilovolts with Area N (Southwest) in the West Sector. The Eastern and Western sections of Area M (New Mexico and Panhandle) are not now interconnected. Interconnections along the juncture of the South Sector with the North Central Sector and the Northeastern Sector are good except along the Virginia-Maryland Border.

Programs for Early Development

Plans have been announced for a number of major advancements in generating facilities, transmission lines and system interconnections. The Virginia Electric and Power Company has nearly completed construction of the first unit of a mine-mouth generating plant at Mt. Storm, West Virginia which will have two 570-megawatt units. The first leg of a 350-mile, 500-kilovolt transmission line will be completed in late 1964. It is contemplated that this plant will be tied into the Northeast Sector at two places, one with the Pennsylvania-New Jersey-Maryland Pool in Area C at a point northwest of Washington, D.C., and the other with the Allegheny Power System in Area D at a point near Morgantown, West Virginia. This will mark the first use of 500 kilovolts in the United States. Figure 125 shows the general route of this line.

500-KV VEPCO TRANSMISSION LINE

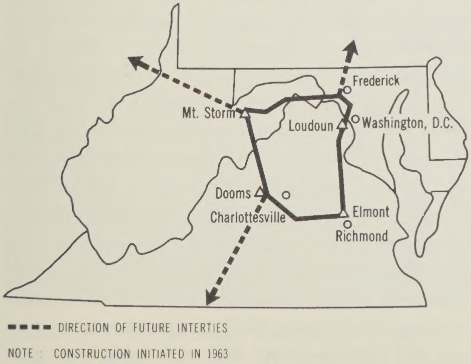

FIGURE 125

In 1962, eleven of the participants in the Southwest Power Pool signed agreements which will provide for the exchange of 1,500,000 kilowatts of seasonal diversity capacity with TVA, the concept of which is depicted in figure 102. The exchange will require the construction of about 940 miles of 500 kilovolt and 220 miles of 345-kilovolt lines as shown in figure 126. A similar seasonal diversity exchange of smaller magnitude—100,000 kilowatts—has been arranged between the Southern System and Florida Power Corporation.

TVA-SCEC POWER EXCHANGE INTERTIE

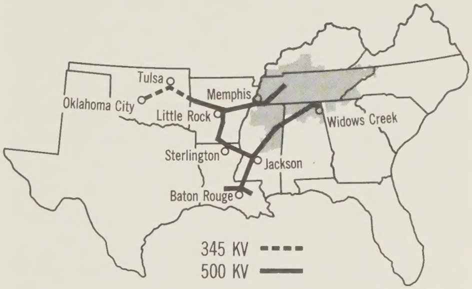

FIGURE 126 *Transmission lines for the TVA-SCEC power exchange are scheduled for initial operation in 1965. Except for the 345 kilovolt circuit from Oklahoma City to Ft. Smith, all lines are 500 kilovolts.*

A score of generating units larger than 300 megawatts are scheduled for installation in the South Sector. These include one of the largest steam-electric units—900,000 kilowatts—in the country, scheduled for service on the TVA system in 1966 and a 1100-megawatt unit which has been ordered by TVA for operation about 1969. Other prospective additions to generating capacity of units as great as 300 megawatts include a 359-megawatt unit in 1964, and two 570-megawatt units in 1965 and 1966 by Virginia Electric and Power Company system, one 375-megawatt and one 650-megawatt unit by Carolina Power and Light, two 350-megawatt units by Duke, four 300-megawatt units and a 360-megawatt unit by the Southern System, six 402-megawatt units by Florida Power and Light System through 1968, a 490-megawatt unit by Florida Power Corporation, a 400-megawatt unit by Louisiana Power and Light Company, a 440-

megawatt unit by Gulf States Utility Company, a 500-megawatt unit by Mississippi Power & Light Company for 1967, a 500-megawatt unit by Arkansas Power and Light Company by 1968, a 500-megawatt unit by Texas Power and Light Company's System for 1965 and a 500-megawatt unit by Texas Electric Service Company by 1967, two 450-megawatt units by Houston Lighting and Power Company by 1966 and 1967, and a 380-megawatt unit by Kansas Gas and Electric Company by 1967. However, some of these same systems are still planning and installing smaller units at numerous locations.

The first leg of a 345 kilovolt backbone line was completed between Texas Power and Light Company and Houston Lighting and Power Company, part of an EHV grid which will eventually extend to the Permian Basin in west Texas. It is contemplated that this line, part of which is now operating at 138 kilovolts will be operating at 345 kilovolts by 1970. Kansas Gas and Electric plans a 345-kilovolt line from Wichita to Kansas City in conjunction with its new 380 megawatt joint participation unit. An interregional 230 kilovolt tie line between Southwestern Public Service Company in the South Sector and Public Service Company of Colorado in the North Sector is expected to be constructed prior to 1970. A contemplated interconnection between Southwestern Public Service Company at Artesia, New Mexico and the El Paso Electric Company at Alamogordo, N.M. would interconnect the two pools operating in load study Area M.

The opportunities for taking advantage of load diversities between parts of the sector, economy of size of generating units and economy of extra high voltage transmission are related to the estimated amount of growth of annual peak load, magnitude and location of load concentrations or load densities, and other related factors such as construction costs, fuel costs, and voltages of existing networks.

Studies indicate that an extra-high-voltage transmission network operating at a common voltage level throughout the South Sector by a particular date, would not be as economical as one or more voltages specifically adapted to each or several of the study areas. In Study Areas E and G the investor owned companies have been using 230 kilovolts. Area F (TVA) has had 161 kilovolts as the highest operating transmission voltage. Most transmission in Area J (Texas) has been 138 kilovolts and lower although a start has been made on an overlying grid at 345 kilovolts.

Since Virginia Electric & Power Company has started a 500 kilovolt grid which will tie into the North Sector, and TVA and the South Central Electric Companies have announced a 500 kilovolt grid for seasonal transfers of energy, it is probable that 500 kilovolt lines may be extended into most areas of the South Sector except possibly Areas J and M. Development of EHV networks to the north and west will be instrumental in advancing inter-sector ties.

The selection of maximum size of generating units is based on many factors such as the rate of utilization of capacity, required reserves of generating capacity, and the capacity of transmission facilities. In order to illustrate a more specific interrelation among such factors, a pattern of generating capacity and transmission facilities is discussed for each study area, to show the over-all general trend rather than a detailed blueprint of each of the several future opportunities.

Study Area E—(Carolinas-Virginia)

In this Study Area the four large investor-owned electric systems, Duke Power Company, Carolina Power and Light Company, South Carolina Electric & Gas Company, and Virginia Electric & Power Company (VEPCO) operate in progressively improving coordination. In 1961 they signed a power pool agreement providing for the study of the feasibility of coordinating the production and transmission of bulk energy. Recently agreements have been consummated and the four companies will begin operations in 1967 as a highly coordinated pool. The pool will plan power resources of the member companies and reserve needs and operations will be on a single-system basis.

Transmission within the area at present is usually at 110 and 138 kilovolts although there are some 230 kilovolt lines superimposed on the circuits of lower voltage. The interconnections with the areas to the west and south are at 110 and 138 kilovolts. At present there are no interconnections with area C to the north. However, a 230-kilovolt tie between Virginia Electric and Power Company, and Potomac Electric Power Company (serving Washington, D.C.) is under construction and 500 kilovolt ties to the north have been programmed.

Most of the generation in the area has been located near the load centers. Coal, the principal fuel of the area, must be transported for distances up to 200 miles. For some load center plants, the cost of fuel transportation has amounted to 100 percent of the at-mine cost. The increasing economy of moving electric energy by wire will continue to be influential in further lowering the cost of transportation of fuel by rail and the relative economics of these two forms of moving energy will have an influence on the location of the large generating units. New generating units in the 1200–1500 megawatt range could be justified economically by 1980.

The summer and winter peaks in the area are practically identical. However, the areas to the west have cheaper fuel and there are opportunities for economy interchanges of energy.

Study Area F—(Tennessee Valley)

This area is served almost entirely by the Tennessee Valley Authority. The City of Memphis now owns and operates an 816 megawatt steam-electric generating station but this plant will be leased to TVA in January 1965 and Memphis will become a wholesale customer of TVA. The area is unique in that TVA supplies the full requirements of the 102 municipals, 51 rural electric cooperatives and 2 small investor-owned utility systems serving in the area in addition to the large requirements of a score of directly served industries and government installations such as the Atomic Energy Commission at Oak Ridge and Paducah.

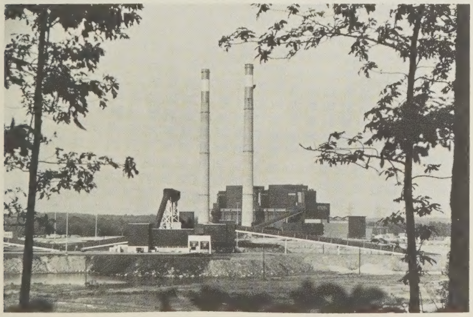

FIGURE 127 *Paradise Steam Plant on the Green River near Paradise, Ky., added 1300 megawatts of steam electric capacity to the Tennessee Valley Authority system. This 2-unit plant was completed in 1963.*

An extensive 161-kilovolt grid covers the area, connecting five of the largest steam-electric plants in the country. Part of the TVA backbone grid is being augmented by the construction of 500 kilovolt lines and terminal facilities. The grid also interconnects with all surrounding utilities in the North and South Sectors. TVA has the largest steam-electric unit in the country now operating with a rating of 650 megawatts and in addition has a 900 megawatt unit under construction and a similar unit on order, the size of which is 1100 megawatts.

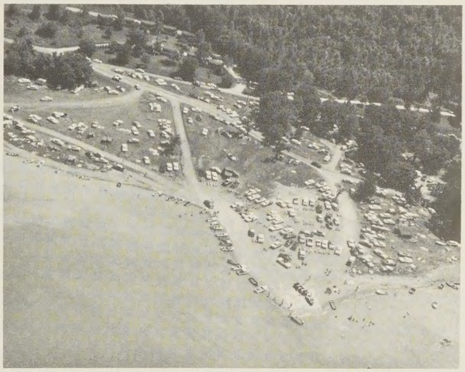

FIGURE 128 *Cumberland River reservoirs provide attractive public use areas. More than 11 million persons visited the Corps of Engineers' reservoirs in the Cumberland basin alone. Lands are also made available to states, counties, and municipal governments for development of public use facilities.*

Coal is abundant and relatively cheap both in the area and the immediate vicinity.

The estimated winter peak of the area by 1980 is expected to exceed its summer peak by over 6,000 megawatts. In 1962, TVA signed an agreement with a member of the Southwest Power Pool in Area K (Middle South) which will provide for an exchange of seasonal diversity as discussed earlier in this part. With regional coordination via the 500 kilovolt grid in the study area and with interconnections to other areas, conventional generating units in the range of 1200 to 1500 megawatts may be used by 1980.

Due to the availability of an abundant supply of low cost coal, nuclear electric generating plants in the TVA area may not be strongly competitive until possibly later in the study period. However, some instances of earlier installation here as in other low cost fuel areas can be expected giving consideration to factors other than strict power production economics.

Study Area G—(Southeastern)

In this study area the electric systems in Georgia, Alabama, eastern Mississippi, and western Florida operate on an integrated basis and are interconnected with the systems in the peninsula of Florida, which operate together. The transmission and power supply plans for each group are being coordinated. While transmission within the area is generally at the 110-kilovolt level, with some at 161 kilovolts, a superimposed 230 kilovolt system is well established in central Georgia and Alabama and a number of 230-kilovolt lines exist in Florida. Interconnections with adjacent areas to the north and west are at 115 and 161 kilovolts.

The area as a whole and the Florida groups have a winter peak, but the Georgia-Alabama Group has a summer peak. At the present, 100 megawatts of seasonal diversity out of a present total of 400 megawatts of seasonal diversity is interchanged between the Georgia-Alabama and Florida groups. By 1980, the seasonal diversity in this area may amount to as much as 2,500 megawatts. This indicated diversity coupled with the load growth and large distances to be spanned, may warrant the use of a 500 kilovolt grid in the area as well as ties of similar voltage to the north and west. As diversity grows, it may be found that a 500 kilovolt tie between Florida and eastern Texas may be economical.

A rather extensive continuation of the present 230 kilovolt system is projected for the Alabama-Georgia portion of the sector to connect local load centers and to serve as interties until heavier lines are installed, and after that to function as a useful backup for the developing 500 kilovolt systems.

Florida has virtually no hydroelectric power and no known opportunity for pumped storage development. This circumstance, coupled with the limited amount of older steam generation for assignment to peaking requirements, portends the need for relatively low capital cost thermal peaking plants, to supplement peaking capacity which can be made available from other areas.

Florida being distant from the coal fields depends primarily on gas and oil as fuel. Both of these fuels are relatively expensive. One of the larger plants of the Tampa Electric Company uses barged coal from Tennessee and Kentucky. The barges return north loaded with crude phosphate. Nuclear power will be a stronger competitor in the period to 1980 in Florida although the opportunities for low cost water shipment and special rail rates of coal to large Gulf Coast plants can be expected to produce competitive fuel prices. Coal is the predominant fuel in Alabama, Georgia, and western Florida. Ample and economic coal deposits are located in the vicinity of Birmingham, and opportunities are available for mine-mouth generation or the alternative of coal delivery by unit train or by barge which may all be in very close competition.

The Alabama Electric Cooperative, Inc. is the only operating generation and transmission cooperative in the area and operates in parallel with the investor-owned systems. Most of the municipal systems in the area are interconnected with the investor-owned utilities; however, a few of them operate with the interconnection open except in emergencies.

In both central Alabama and northern Georgia, a few generating units in the 600–800 megawatt range could be economically justified by 1980. In southern Florida, a few units in the 750–1000 mega-

FIGURE 129 *Weiss Dam is one of six Alabama Power Co. dams, under FPC license, which develop the Coosa River from its mouth to Rome, Ga. They provide power, flood control, and other benefits. Navigation locks at each dam are authorized for future Federal construction.*

watt range could be used by 1980. After regional coordination via a 500-kilovolt grid and with interconnections to other areas outside of the South Sector, conventional steam-electric units in the 1000–1200 megawatt range might be generally expected with a few in the 1200–1500 megawatt class.

Study Area J—(Texas Area)

Much of Texas is an area of relatively low rainfall, and for many inland plants cooling water is supplied from artificial reservoirs and cooling towers. The generating plants in the past have been largely located near load centers and are relatively close to natural gas fields which furnish the boiler fuel. Many large new power plants are being sited on major reservoirs.

The utilities in this area are interconnected mainly at 138 kilovolts but a 345-kilovolt backbone grid is in service between Dallas and Houston. There are two main groups of utilities in this area, each forming more or less separate pools but strongly interconnected. The rates for the electric companies operating in Texas are subject to regulation only by the major cities they serve because no state commission exists. The Federal Power Commission has been informed that interconnections with utilities operating interstate facilities are normally open or operate with reverse current relays for the purpose of preventing the flow of interstate energy. There are no major interconnections between utilities in Study Areas J and M.

Central Texas has a summer peak that presently exceeds its winter peak by about 3,000 megawatts. This seasonal diversity is estimated by the Commission staff to amount to over 8,000 megawatts by 1980. Potential exchanges of such diversity in either Area J or K with coordination areas to the Northeast might offer the earliest opportunity for consummating an economic interchange because of the lesser transmission distances involved. Figure 116 and table 59 outline an alternative to this Northeast exchange through the construction of a 750-kilovolt DC tie between Study Area J and the Pacific Northwest. A variation of such an exchange with the Northwest is suggested as the result of the recently approved Pacific Northwest-Pacific Southwest Intertie. This program provides for the construction of two 500-kilovolt circuits, one in 1967 and the other in 1968, from northern Oregon through the central valley of California to Los Angeles, as well as two 750-kilvolt direct-current circuits from northern Oregon through western Nevada, one in 1968 to Los Angeles, and the other in 1971 to Hoover Dam. This construction should improve the economics of exchanging potential seasonal diversity capacity via long-distance EHV lines between systems in the Pacific Northwest and central Texas, and could advance the time when such exchanges would be economically feasible. In another direction, as mentioned in the discussion of Study Area G, it appears that there may be opportunities for exchange of some of this seasonal diversity with the areas in the Southeast.

The central Texas area for a number of years has experienced a rate of load growth which is among the highest in the nation. Steam-electric generating units under construction are in the range of 400 to 500 megawatts. With interregional coordination, conventional steam-electric units in the 1000–1200 megawatt range would be expected in 1980.

Study Area K—(Kansas, Missouri, Arkansas, Oklahoma, Louisiana, Mississippi)

In this study area, all of the large systems are either members or associates of the Southwest Power Pool. It is a voluntary association and each system retains its separate identity and all dealings with other systems are on a contractual basis. There are a number of separate pooling agreements among the members and associates of the Southwest Power Pool. Recently the Kansas Gas and Electric Company, Kansas Power and Light Company, Missouri Public Service Company, the Empire District Electric Company, and the Kansas City Power and Light Company which is in the North Central Sector, formed a five member pool. They will share reserves, provide mutual assistance in emergencies, and stagger construction of additional generating units on a coordinated basis so that large units can be installed. Three of these companies together with the Associated Electric Cooperative, Inc., an association of six G & T Cooperatives, have signed an agreement to purchase hydro power and energy from Southwestern Power Administration. By coordinated scheduling of the purchased hydro, they will be able to effect and share in economies through combined use of relatively low cost peaking capacity.

The area has a well-established grid operating at 161, 138 and 115 kilovolts which interconnects with utilities to the north, east and southwest. However, the connections to the southwest have been reported to be normally open or with reverse current relays for the purpose of preventing the flow of interstate energy to some systems in Texas.

Eleven members of the Southwest Power Pool, known as the South Central Electric Companies (SCEC) have agreed to exchange seasonal diversity capacity with TVA, as discussed earlier in this part. The area had a summer peak in 1963 that exceeded the following winter peak by 2,600 megawatts. By 1980, this seasonal diversity is estimated to amount to about 8,000 megawatts, the same magnitude as anticipated for the Central Texas study area.

The area has excellent natural gas reserves, and coal is available in Missouri, eastern Kansas, eastern Oklahoma and western Arkansas. Steam-electric generating units in the 500 megawatt size range are under construction in the area. With the new pooling agreements and the new 500 kilovolt SCEC grid, generating units in the 1000–1200 megawatt range could be economically justified by 1980.

Study Area M—(New Mexico and Panhandle)

The load centers in Study Area M are small, and the transmission distances between them are great. The New Mexico Power Pool operating in central New Mexico is composed of the El Paso Electric Company, Public Service Company of New Mexico, Community Public Service Company, Plains G & T Cooperative, and the Rio Grande Project of the Bureau of Reclamation. These systems are interconnected by 115 kilovolts but, because of limited interconnections and the distance between systems, none of the members has installed units larger than needed for its own requirements, nor have they sold capacity to other members in order to stagger construction. Sections of a 230-kilovolt interconnecting line from El Paso to Albuquerque have been completed. A 230-kilovolt line has been built from this pool to Arizona Public Service Company's Four Corners plant in the West Region. This plant is in the Four Corners coal field which has over one billion tons of commercially mineable coal.

In northwest Texas and eastern New Mexico, the Southwestern Public Service Company provides the power supply for most of the area. Its interconnections with adjacent systems in Texas are reported to be operated normally open; however, a new 115-kilovolt tie has been made to Western Light and Telephone Company in Kansas to provide reserve backup for fringe load areas of the two systems. This line will not be used for continuous connected synchronous operation of the two companies. Due to the ample supply of cheap natural gas and coal, nuclear power plants may not be competitive until after 1980. With regional coordination Study Area M could support generating units in the 800–1000 megawatt range by 1980.

Summary for South Sector

Table 63 summarizes the sources of generation by general categories and for thermal plants by groups of unit sizes which have been included in the study of the general pattern for meeting the 1980 loads in the South Sector. The table includes existing generation estimated to be retained for service through 1980. The general locations of new facilities included in the capacity and energy resource pattern from 1965 to 1980 are depicted on figure 116.

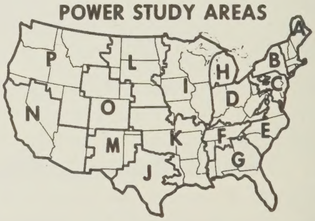

TABLE 63

South Sector

1980 Capacity Supply in Gigawatts

	Area						Southern sector
	E	F	G	J	K	M	
Source of capacity:							
Diesel and gas turbines	0. 1	0	0. 3	0. 4	1. 3	0. 1	2. 2
Conventional hydro	4. 6	4. 5	4. 7	0. 4	2. 8	0	17. 0
Pumped storage	0. 5	1. 6	1. 0	0	1. 0	0	4. 1
Steam-electric fossil fuel:							
0–400 mw units	9. 8	8. 9	11. 2	11. 0	12. 8	2. 3	[1] 56. 0
400–800 mw units	1. 2	1. 5	3. 6	1. 5	3. 6	2. 0	13. 4
800–1200 mw units	7. 0	2. 9	11. 0	6. 0	11. 0	1. 8	39. 7
1200 mw and over	2. 6	10. 4	3. 6	2. 7	3. 6	0	22. 9
Nuclear:							
0–400 mw units	0	0	0	0	0	0	0
400–800 mw units	2. 4	0. 5	0	0. 6	0	0	3. 5
800–1200 mw units	0	1. 0	6. 2	0	0	0	7. 2
1200 mw and over	0	0	2. 7	0	0	0	2. 7
Total capacity	28. 2	31. 3	44. 3	22. 6	36. 1	6. 2	168. 7
Percent distribution:							
Diesel and gas turbines	0. 4	0	0. 7	1. 8	3. 6	1. 6	1. 3
Conventional hydro	16. 3	14. 4	10. 6	1. 8	7. 7	0	10. 1
Pumped storage	1. 8	5. 1	2. 2	0	2. 8	0	2. 4
Steam-electric fossil fuel	73. 0	75. 7	66. 4	93. 8	85. 9	98. 4	78. 3
Nuclear	8. 5	4. 8	20. 1	2. 6	0	0	7. 9

[1] This consists of 543 units below 200 megawatts totaling 37.7 gigawatts of which 467 units totaling 32.6 gigawatts were in service in 1960; and 76 units between 200–400 megawatts totaling 18.3 gigawatts of which only 35 totaling 7.8 gigawatts were in service in 1960.

PART E—PATTERN OF POWER SUPPLY—NORTH CENTRAL SECTOR

The North Central Sector is outlined in figure 116. As the map shows, the sector extends from Lake Michigan and the Illinois-Indiana state line on the east to the western borders of the states of Colorado and Wyoming, and includes a small eastern portion of Montana. In the north-south direction, the sector extends from the Canadian border to an irregular mid-continent line including Colorado, Nebraska, northern Missouri and all of Illinois. The area of the North Central Sector corresponds to that of FPC power supply regions IV and VI.

The peak loads for 1962 in the North Central Sector were 22,500 megawatts (22.5 million kilowatts), and the projections for 1970 are 38,600 megawatts and for 1980, 70,400 megawatts. About 14 percent of the power requirements for the nation in 1980 will be located in the North Central Sector. Non-coincident loads for 1960 and 1962, together with estimates for 1970 and 1980 are given in the following tabulation.

Load Growth In The North Central Sector

(Megawatts)

Area	1960	1962	1970	1980
I	16, 997	18, 728	31, 500	57, 600
L	1, 958	2, 117	3, 830	6, 950
O	1, 382	1, 600	3, 280	5, 820
Total	20, 337	22, 445	38, 610	70, 370

Load Distribution

The principal load centers are located in the eastern half of the sector, and are concentrated in the metropolitan areas of Chicago, Milwaukee, Minneapolis-St. Paul, Omaha, Des Moines, Davenport, Kansas City, and St. Louis. Denver is the largest load center in the western portion of the North Central Sector but, as indicated on figure 111, the western portion is an area of low density and most of the load centers are quite far apart. Major load centers are identified and located on figure 117.

Operating Utilities

Large investor-owned utilities are the principal suppliers of electric energy to the major metropolitan centers in the eastern portion of the sector. Rural electric cooperatives are well established throughout the entire sector and generation-transmission type (G&T) cooperatives are functioning in Colorado, Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin. The largest numbers of municipal systems in the sector are found in Nebraska (136), Iowa (132), and Minnesota (126).

Altogether in the North Central Sector there are 123 investor owned systems, 329 cooperatives, and 796 publicly owned systems, comprised of municipal systems and public utility districts. Investor owned companies serve 79 percent of the loads in the area, the cooperatives 8 percent, and the public agencies the remaining 13 percent. The Federal government generates 5 percent of the electric energy in the area, its output being sold principally to municipalities and cooperatives. In 1962 about 40 percent of all the power generated by "G&T" cooperatives in the United States was produced in the North Central Sector with cooperatives in Wisconsin alone accounting for almost one-fourth of this amount.

The five largest of the 123 investor-owned electric systems supply about 50 percent of the electric loads in the sector. Commonwealth Edison Company of Chicago alone accounts for nearly 25 percent and Union Electric Company of St. Louis for eight percent. The largest municipal system in the sector is Kansas City, Kansas, which had a peak load in 1963 of 196,000 kilowatts.

There are no investor-owned companies in Nebraska except for two small systems. Many towns in the state of Nebraska are served by municipal systems. Some of the municipalities provide their own generation but most of them obtain their power from state-sponsored public power districts which carry out the principal generation and transmission functions in the state. The eight cooperatives in Nebraska function only for the distribution of power.

The Bureau of Reclamation is the marketing agency for hydroelectric power from Federal projects located in the Missouri River basin. The power is marketed largely to preference customers—municipal systems and cooperatives—over a transmission network which generally has a main line voltage of 230 kilovolts. At the end of 1963, some 1,565,000 kilowatts of installed Federal capacity were connected to the U.S. Bureau of Reclamation transmission system. Numerous wheeling arrangements have been made by the Bureau with utilities in the area for delivery of power to preference customers.

Interconnected Operation and Power Pools

All the large electric utility systems in the North Central Sector, with the exception of those in Wyoming and Colorado, operate in parallel and are a part of the large Interconnected Systems Group which generally spans the United States east of the Rockies. Systems in Wyoming and Colorado which are associated together in a pool designated as the Rocky Mountain Power Pool are interconnected with the Northwest Power Pool sufficiently to operate in parallel with that pool. Several power pools and one informal arrangement resembling a pool operate within this general framework of interconnection.

In the Rocky Mountain Power Pool the Federal, public utility district, and municipal systems participate in the pooling arrangement. Some of the pools, such as the Upper Mississippi Valley Power Pool and the Iowa Power Pool, include cooperative systems as members. Such pools usually form operating committees to coordinate operating and maintenance schedules. Interchanges which are commonly included in the pooling arrangements provide for economy energy transactions, sharing of reserves, and reserve support in emergencies. In some cases pooling has reached the stage of joint planning of new capacity to enable the utilization of larger units with construction carried out on a staggered basis.

A recently formed new pooling organization known as the Mid-Continent Area Power Planners (MAPP) includes 15 investor owned utilities, six "G&T" cooperatives, City of Cedar Falls, Iowa, the Omaha Public Power District, and the Manitoba (Canada) Hydroelectric Board. The systems of the MAPP group operate in Minnesota, Iowa, Wisconsin, Missouri, North Dakota, South Dakota, Montana, Wyoming, and Nebraska, and the Canadian province of Manitoba. The organization provides coordination of the activities of MAPP members in planning and constructing facilities. The group proposes to operate as a coordinated electric power system utilizing the latest technological developments in high voltage transmission, generation, and in the utilization of fuel sources. The organization has outlined a program for constructing extra-high voltage transmission facilities between principal load centers in the area which is described generally later in this Part.

The organization of the Mid-Continent Area Power Planners pool was paralleled by the formation of another power pooling group known as the Missouri Basin Systems Group (MBSG) made up of municipalities, rural electric cooperatives, public power districts, and state agencies operating over much of the area served by the Mid-Continent Area Power Planners pool. The Missouri Basin Systems Group was originally comprised of 105 electric utilities principally centered in the States of Minnesota, North Dakota, South Dakota, Montana, Nebraska and Colorado. In January 1963, a pooling agreement between members of the Missouri Basin Systems Group and the Federal Government was effected which will permit the group to utilize available capacity of the Federal transmission system in the area. The group has a planning committee which makes studies of facilities which should be built, and their operation and coordination among system members and power pools in adjacent areas. Much of the planning will concentrate on the building of large generating plants utilizing the coal resources of the area, particularly its lignite, with membership-constructed transmission lines feeding the output of such plants into the Federal system.

Another interconnected group in this sector is the Illinois-Missouri Pool which has operated under a formal interconnection agreement since 1956. The agreement covers the interchange of firm, economy and emergency energy and the planning of new installations of generating equipment on a more economical basis as to timing, location, and unit sizes. The members of the pool are: Illinois Power Company; Central Illinois Public Service Company; Union Electric Company; and Electric Energy Incorporated, jointly owned by the three preceding companies and Kentucky Utilities, Inc.; and two subsidiaries of Union Electric Company—Missouri Edison Company, and Missouri Power and Light Company.

An example of informal pooling which yields many of the benefits of a formal pool is the group of interconnection agreements among a number of companies adjoining the Chicago metropolitan area, namely, Wisconsin Electric Power, Central Illinois Electric and Gas, Commonwealth Edison and American Electric Power (in the Northeast Sector). These agreements provide for emergency and economy exchanges, firm capacity sales and purchases, and maintenance coordination. These companies engage in joint planning for capacity additions and system interties. Seasonal diversity exchanges in 1964 (300 megawatts of summer capacity from west to east and 150 megawatts of winter capacity from south to north) have resulted in savings in the amount of installed generating capacity.

Present Generating and Transmission Facilities

About 88 percent of the electric energy used in the North Central Sector is presently supplied by conventional steam-electric generating plants. Most of the remaining generation is supplied from hydroelectric resources and much of this from the Federally owned and operated projects in the Missouri River Basin. About 120 small privately owned hydroelectric projects are located on the tributaries of the Upper Mississippi River in Wisconsin and Minnesota. Only 283,000[12] kilowatts of nuclear power are now in productive operation in the North Central Sector, a mere one percent of the total supply.

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[12] 200,000 kw of this amount is accounted for by the Dresden Station of Commonwealth Edison Company.

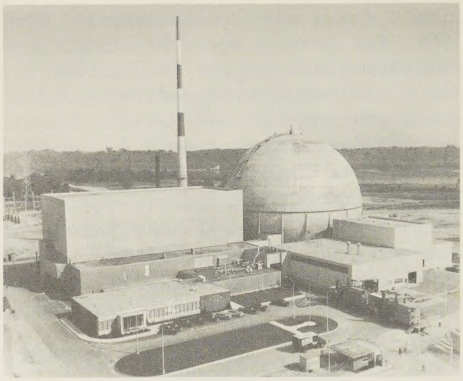

FIGURE 130 *The 200-megawatt Dresden Nuclear Power Station, located 50 miles southwest of Chicago, was the first full-scale, privately-financed nuclear power station in the United States. It began operations in 1960.*

The principal fuel sources for conventional steam-electric generation in the sector are coal and natural gas. Many of the larger plants are equipped to utilize both fuels, burning natural gas when off-peak supplies are available. Coal resources in the eastern part of the sector are located in south central Illinois, in west central Missouri and southern Iowa. In the western part of the North Central Sector coal beds are scattered in Wyoming and Colorado. A large reserve of lignite is situated in North Dakota and eastern Montana. Although some local natural gas is produced in the southern and northwestern part of the sector, most gas is supplied by interstate pipe lines from the South Sector. Steam plants along the navigable rivers receive much of their supply of coal by barge shipment. Coal to other areas of the North Central Sector, other than locally produced, is moved largely by rail.

The western part of the sector is an area of generally low load density with a scattered distribution of the small to moderate sized load centers served by a large number of electric systems of diverse ownership which have not as yet pooled their loads to take the fullest possible advantage of scale in the construction of generating stations. These factors account for the prevailing pattern of steam-electric generating plants of relatively small size located close to load centers.

The great majority of principal transmission lines of electric utility systems in the North Central Sector operate at voltages of 138 and 161 kilovolts; yet, there is considerable mileage of 115 kilovolt circuits. Notable exceptions are the transmission lines of the main grid of the Bureau of Reclamation, principally in North and South Dakota but extending into western Minnesota and Iowa, which operate at 230 kilovolts. In a few other areas near metropolitan centers 230 kilovolt transmission has been in operation nearly 40 years to facilitate the movement of power to heavier loads, and recently lines of 345 kilovolts have been added in the Chicago area.

There are reasonably good interconnections between systems in the North Central and Upper Missouri Basin Study Areas (I and L) (See Figure 116). There are three 345 kilovolt circuits between electric systems in this sector and to the east (Study Areas I and D). The interconnections to the south from the North Central Sector are generally of the 161 kilovolt transmission class and are not of relatively large capacity. Interconnections between Study Area O and the West Sector are being strengthened by the construction of 230 kilovolt circuits. There are at present no significant ties between Study Areas L and O. The line of separation roughly follows the western boundaries of Colorado, Wyoming, and the eastern portion of Montana.

Programs for Early Development

Plans have been announced for a number of major advancements in generating facilities, transmission lines and system interconnections in the region. Commonwealth Edison Company has begun construction this year of a two unit, 1,120 megawatt generating station in the central Illinois coal fields near Kincaid, 15 miles southeast of Springfield. Two 345 kilovolt transmission lines will be constructed to transmit power 175 miles from the Kincaid station to the Chicago load area. A third circuit will connect the plant with neighboring utilities expanding Edison's interconnections to the south and east. Other prospective additions to generating capacity range from units of 560 megawatt size downward.

General plans have been formulated by participants in the recently organized Mid-Continent Area Power Planners (MAPP) for the construction of a large network of extra-high voltage transmission lines principally at the 345 kilovolt level that will link the major load centers located in Study

Area I and the northern portion of Area L. The Twin Cities—Milwaukee-Chicago 345 kilovolt, 470 mile line is now under construction and is scheduled to be in service in 1966. This circuit will provide interconnection capacity for coordination among the Upper Mississippi Valley Power Pool, the Eastern Wisconsin Utility Group and the Commonwealth Edison Company, the latter two not members of the MAPP organization. The 520 mile long Twin Cities to St. Louis 345 kilovolt line is to be completed in 1967. It is to be constructed by seven members of the MAPP group, namely Union Electric Company, Iowa Electric Light and Power Company, Iowa-Illinois Gas and Electric Company, Interstate Power Company, Iowa Public Service Company, Iowa Southern Utilities Company and Northern States Power Company. This 345 kilovolt line will facilitate coordination among the Upper Mississippi Valley, Iowa and Illinois-Missouri Power Pools. The Chicago-St. Louis and St. Louis-Kansas City 345 kilovolt lines are expected to be completed by 1970. Also, some sections of 230 kilovolt lines in northern Minnesota and North Dakota are to be completed by 1970.

In North and South Dakota and eastern Montana, the extensive 230 kilovolt system of the U.S. Bureau of Reclamation is to be augmented by the construction of additional 230 kilovolt lines from the Corps of Engineers' 595 megawatt hydroelectric station at Oahe Dam to New Underwood in South Dakota and thence to Stegall, Nebraska; in Montana, from the 250 megawatt Yellowtail hydroelectric project to Dawson County and in South Dakota, from the Corps' 468 megawatt hydro station at Big Bend Dam to Sioux Falls. The Bureau network will be strengthened by continuation of a 230 kilovolt line from Stegall in western Nebraska to Cheyenne, Wyoming and to Hayden, Colorado where it will be linked with the 230 kilovolt interconnected network of the Colorado River Storage Project. The principal network in Wyoming is the 230 kilovolt system of Pacific Power and Light which serves local mining and oil and gas well requirements, interconnects with the Bureau of Reclamation network at points north, east, and south and with Utah Power and Light on the west and Montana Power Company on the north. Pacific Power & Light plans an early expansion of its relatively new Dave Johnston mine-mouth generating station on the N. Platte River and the construction of a new mine-mouth plant at Cherokee in south central Wyoming. In addition to supplying local loads, the company is planning transmission service arrangements with connecting utilities to move firm and offpeak energy to its main system in the Pacific Northwest.

Some opportunity appears to exist within the North Central and Upper Missouri Basin Study Areas (I and L) of the North Central Sector for transfers of seasonal diversity power. If future trends in seasonal peaks follow the estimated pattern, the sum of the indicated winter peaks in the North Central Sector in 1980 will be about 68,000 megawatts and the total of summer peaks is indicated to be only a few hundred kilowatts more. It can be expected that strengthened interconnections as proposed in a north-south direction will be able to accomplish, among other things, the complete exchange of any seasonal diversity which may develop, including some supplemental exchanges, if needed, with the system of the Manitoba Hydro-electric Board in Canada. The strengthening of interconnections in an east-west direction within the North Central Sector and across the boundaries of this sector with neighboring east-west systems will provide many benefits and permit the flow, alternately in an east and west direction, of an amount of power needed to satisfy time zone diversity.

Perhaps as important as any other consideration, strengthened interties covering the entire sector would enable broader pooling of loads in the planning of additional generating capacity so that the utilities could all share in the savings of utilizing larger units.

There is no lack of reasonably accessible resources for the generation of electric energy to meet power requirements for many decades ahead. The total generating capacity which it is assumed will be needed in the North Central Sector to supply the sector's non-coincident peak demand of approximately 70,000 megawatts estimated for 1980, will be about 76,000 megawatts.

There are a number of good opportunities for the further development of hydroelectric power in the western portions of the sector. The attractive sites include Snake Narrows development of 270 megawatts on the Snake River in Wyoming.

Opportunity may exist within the period of this survey analysis for the importation from Canada of relatively large amounts of hydroelectric power generated on the Nelson River system, which would involve an average transmission distance to the border of about 500 miles. About 2 million kilowatts of power from such sources in Manitoba can probably be developed before 1980.

Perhaps 2,100 megawatts of pumped storage could be utilized to advantage by 1980 to supply power for peak loads in the eastern portion of the sector, as indicated in Figure 116. A number of sizable opportunities for pumped storage projects are available along the Mississippi River and in the Lake Michigan region.

Fuel supplies needed for major expansions in conventional steam-electric generation in the eastern part of the North Central Sector are abundantly available in the bituminous coal fields of south central Illinois, lower Indiana, and western Kentucky, west central Missouri and southern Iowa. Large deposits of lignite are situated in North Dakota and eastern Montana. The locations of these deposits are indicated on figure 27, chapter 3.

Water as well as rail transportation is available for movement of fuel supplies to many of the major centers of generation. The navigable waterways of the Mississippi, Ohio, Tennessee and Illinois Rivers afford economic access to coal fields and the waterways of the Mississippi, Illinois and Missouri Rivers and Lake Michigan permit extensive distribution of coal supplies into the sector.

Although an extensive network of natural gas pipelines extends into the North Central Sector from gas fields in Oklahoma, Kansas, Louisiana and Texas, the utilities are not in a position to construct new generating stations which are designed only for the burning of natural gas unless they can contract on a long-term basis for the purchase of natural gas at or near prevailing prices. In view of the availability of alternative fuels at competitive prices and the rapidly expanding demands for natural gas for other uses it is unlikely that such contracts will be consummated by the utilities of this sector.

On the basis of present forecasts, it is likely that some nuclear power will become competitive by 1970 in part of the sector where conventional fuel costs remain above 25 cents per million Btu. Joint participation in nuclear plants of large size will be studied closely and this opportunity is enhanced by the presence of a well developed inland waterway system for shipping large size reactor vessels. However, prospects for new nuclear capacity in the area will be affected by the recent and prospective major reductions in fuel transportation costs for large coal movements by unit train. A very substantial reduction in costs also can be achieved for conventional power plants by stepping up the size of generating units. The EHV grids that will facilitate larger generating units may also be used as an alternative to shipment of coal by moving energy from mine-mouth plants to load centers. In view of such opportunities and trends, it is considered unlikely that nuclear generation will surpass the economy of conventional methods in low cost fuel areas of the North Central Sector prior to 1970 and possibly 1975.

Study Areas I, L and O of the North Central Sector are quite different from each other with respect to magnitude, distribution and distance between load centers. About 83 percent of the total peak load of the sector is in Study Area I, comprised of Illinois, Wisconsin, Minnesota, Iowa and northern Missouri, and the remainder is almost equally divided between the other two areas, Area L including North and South Dakota, Nebraska and eastern Montana and Area O, Wyoming, Colorado and western Nebraska. The opportunities for taking advantage of economy of size of generating units and extra high voltage transmission are related to the estimated amount of growth of annual peak load of the study areas making up the sector.

Although some overlapping is inevitable, the load estimates suggest that an extra high voltage transmission network operating at a common voltage level would not be as economical as one with voltages appropriate to the study areas. The geographic distribution and magnitudes of load centers suggest that 345 kilovolt transmission is particularly adaptable for use in Study Area I and for its connections to the east and south, and 230 kilovolts for Areas L and O. The selection of maximum size of generating units which we depict is based on many factors, including the rate of utilization of capacity, required reserves and transfer capacity available via transmission facilities. A possible pattern of generating capacity and transmission facilities is discussed for each study area, to show a possible trend rather than a blueprint of future opportunities.

One overall pattern of power supply for the sector loads of 1980, and certainly there can be many others, which embodies a good competitive balance in generation types and achieves the benefits of large scale low cost supply under fully coordinated planning and operation is reflected in Table 64. Steam-electric plants using fossil fuel constitute 76 percent of the projected power supply for 1980 with nuclear accounting for 13 percent and conventional hydroelectric for 5 percent of the remainder. About 40 percent of the 1980 capacity will be in units of 800 megawatts or larger.

Study Area I—(North Central)

In this study area, the major electric systems in eastern Wisconsin and northern Illinois now operate together. They have interchange arrangements with the Illinois-Missouri pool and with the American Electric Power System to the east. The power systems in Minnesota, Iowa, northern Missouri, western Wisconsin, eastern North Dakota, eastern South Dakota and eastern Nebraska are members of the MAPP group.

POWER STUDY AREAS

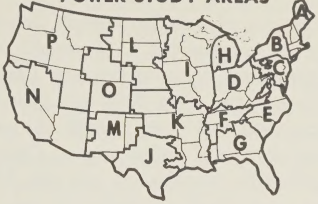

TABLE 64

North Central Sector

1980 Capacity Supply in Gigawatts

	Area I	Area L	Area O	North central sector
Source of capacity (megawatts):				
Diesel and gas turbines	1.1	0.7	0.1	1.9
Conventional hydro	0.9	1.9	1.3	4.1
Pumped storage	2.1	0	0.3	2.4
Steam-electric fossil fuel				
0–400 mw units	19.8	2.3	2.9	[1] 25.0
400–800 mw units	7.3	2.0	1.2	10.5
800–1,200 mw units	5.8	0	0.6	6.4
1,200 and over mw units	15.8	0	0	15.8
Nuclear				
0–400 mw units	0.1	0	0	0.1
400–800 mw units	1.2	0.4	0.6	2.2
800–1,200 mw units	8.0	0	0	8.0
Total capacity	62.1	7.3	7.0	76.4
Percentage distribution:				
Diesel and gas turbines	1.8	9.6	1.4	2.5
Conventional hydro	1.4	26.0	18.6	5.4
Pumped storage	3.4	0	4.3	3.1
Steam-electric fossil fuel	78.4	58.9	67.1	75.5
Nuclear	15.0	5.5	8.6	13.5

[1] This consists of 394 units below 200 mw totaling 17.5 gw of which 325 units totaling 13.2 gw were in service in 1960; and 28 units between 200–400 mw totaling 7.4 gw of which only 10 totaling 2.7 gw were in service in 1960.

Announced transmission plans would tie members of several power pools together at 345 kilovolts thereby providing facilities for more widespread coordination. The transmission system would include a loop of 345 kilovolt circuits connected with 345 kilovolt ties to the east and extending from Chicago to St. Louis, Kansas City, Omaha, Sioux Falls, Twin Cities, Appleton, Milwaukee and Chicago. Added links would include a cross tie from the Twin Cities to St. Louis via Cedar Rapids a cross tie from Chicago to Omaha via Des Moines and a 345 kilovolt circuit from Twin Cities to Garrison via Fargo.

The Chicago to Omaha tie-line, because of its possible extra duty of linking the central midwest load area with the prospective long distance ties to the far west, might well be planned for 700 kilovolts.

The capacity of each 345 kilovolt circuit is estimated at 350 megawatts. This would provide a total transmission capacity between Chicago, St. Louis, Omaha, the Twin Cities and Milwaukee of 1000 megawatts and make possible the utilization of generating units of optimum size. Other sizable benefits through coordination via this EHV network are more rapid utilization of new capacity additions through staggering of generation additions, and reduction in requirements for the total amount of capacity by taking advantage of load diversity. Although the fuel costs vary sufficiently throughout Study Area I, to make economy energy exchanges attractive, such exchanges will yield relatively small savings when compared to the others.

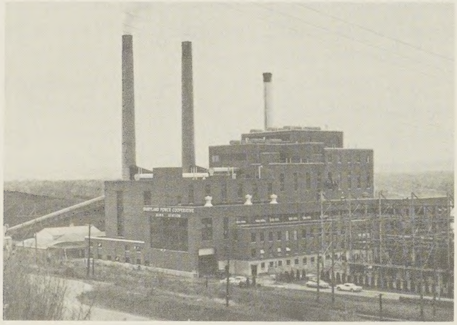

Figure 131 *The Alma Steam Power Station, on the Mississippi River, 60 miles north of LaCrosse, Wisc., with a 205,000 kilowatt station capability, is the largest power producer of the Dairyland Power Cooperative.*

Opportunities are available for taking advantage of locating new power plants in the coal fields of Illinois, Missouri and Iowa and also along the navigable waterways which extend as far north as St. Paul-Minneapolis on the Mississippi River. The currently high cost coal areas in Wisconsin and Minnesota could take part in economy energy transactions and would be logical locations for the earlier nuclear power plants of this sector.

With regional coordination via the 345 kilovolt grid in the study area and with interconnections to other areas, conventional generating units in the 1,200–1,400 megawatt range in the eastern part of the area and up to 1,000 megawatts in the western part might be utilized by 1980.

Study Area L—(Upper Missouri Basin)

The load centers in Study Area L are relatively small and far apart. The area has a 230 kilovolt transmission network based on the Missouri River hydroelectric system of the U.S. Bureau of Reclamation. Based on the estimated loads for 1980, a 230 kilovolt network with some 345 kilovolt circuits should be adequate for area needs for the years to 1980. A network of 500 kilovolt lines superimposed over the 230 kilovolt system may not be needed until after 1980.

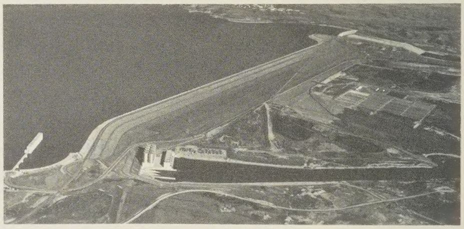

Figure 132 *The Garrison Dam and Reservoir, one of six major mainstem projects constructed by the Corps of Engineers on the middle reaches of the Missouri River, stores 24,500,000 acre-feet of water for flood control, navigation, irrigation, power and recreation purposes. The five unit power plant has a total capacity of 400,000 kilowatts. The dam, completed in the 1950's, contains 66.5 million cubic yards of earth fill.*

The selection of unit sizes will depend in large measure upon how soon the lignite resources in North Dakota and eastern Montana will be developed as base load power supply for long distance transmission. The generating capacity suggested herein for 1980 gives consideration to the relatively small load centers in the study area and to the large distances between them. High transmission costs due to these factors indicate that up to 1980 mine-mouth lignite power plants may be used as a source of power largely for areas within a few hundred miles. On this basis the largest generating unit for Study Area L is limited by the rate of annual growth of load and by reserve support obtainable from the transmission network. With coordination throughout the study area and with adjacent areas, conventional lignite burning steam-electric units of 600 megawatts appear economic. In addition, the area could support a 400 to 600 megawatt nuclear power plant. Without coordination, it is questionable whether generating units larger than 300 megawatts would be justified.

If further experience demonstrates that large lignite fueled plants are sufficiently economical to warrant long distance power transmission before 1980, generating units in the 1000–1200 megawatt range could come into being.

Study Area O—(Colorado-Wyoming Area)

Except for Denver, the load centers are small in Study Area O and intervening transmission distances are long. The maximum size of generating units in this study area is determined in large measure by annual rate of load growth and the support provided by the contemplated 230 kilovolt transmission network. Development of transmission ties and coordination with adjoining areas, particularly Area M, could accelerate the installation of large units.

Many patterns of power supply could be developed for this area but that suggested in Table 64 is believed feasible although detailed economic studies have not been made for each project. Coal resources are extensive in both Colorado and Wyoming and could contribute not only to the power supply in Area O, but also provide large amounts of power for export to other areas. Without such export, however, maximum unit sizes may be limited to 500 to 600 megawatts in the period to 1980. Nuclear generation may become competitive by the latter part of the study period but is not expected to become an important source of power generation in the area before 1980.

Summary for North Central Sector

Table 64 summarizes the principal kinds of generating capacity assumed for the North Central Sector for 1980. These are the kind of capacity and amounts which have been included in this study of 1980 loads and capacities. Existing generating units expected still to be in service in 1980 are included. The general locations of new facilities assumed for 1980 are depicted in Figure 116.

Table 65 is a summary of existing pools and coordinating groups operating in the North Central Sector.

TABLE 65

North Central Sector Pools

Interconnected systems group:

- Illinois-Missouri Pool:
  - Central Illinois Public Service Co.
  - Illinois Power Company
  - Union Electric Co.
  - Electric Energy, Inc. (owned by above 3 companies)
  - Missouri Edison Co.
  - Missouri Power & Light Co.
- Southwest Power Pool:
  - Kansas City Power & Light Co.
  - St. Joseph Light & Power Co.
  - Missouri Edison Co. (Also in Ill.-Mo. Pool)
  - Missouri Power & Light Co. (Also in Ill.-Mo. Pool)
  - Omaha Public Power District
  - Nebraska Public Power System
- Interconnected Utilities of Eastern Wisconsin:
  - Wisconsin Electric Power Co.
  - Wisconsin Michigan Power Co.
- Interconnected Utilities of Eastern Wisconsin—Continued
  - Wisconsin Power & Light Co.
  - Wisconsin Public Service Co.
  - Madison Gas & Electric Co.
- Upper Mississippi Valley Power Pool:
  - Cooperative Power Association (18 member cooperatives supplying southern and western Minnesota)
  - Interstate Power Co.
  - Lake Superior District Power Co.
  - Minnesota Power & Light Co.
  - Minnkota Power Cooperative
  - Northern Minnesota Power Associations (8 or 9 cooperatives)
  - Northern States Power Co.
  - Otter Tail Power Co.
  - Dairyland Power Cooperative
  - Rural Cooperative Power Association
  - North Dakota Sub-Area Pool
  - United Power Association

Interconnected systems group—Con.
- Northern Illinois Area
  - Commonwealth Edison Co.
  - Central Illinois Electric & Gas Co.
  - Central Illinois Light Co.
- Iowa Power Pool
  - Iowa Power & Light Co.
  - Iowa Electric Light & Power Co.
  - Iowa-Illinois Gas & Elec. Co.
  - Iowa Public Service Co.
  - Iowa Southern Utilities
  - Corn Belt Power Cooperative
- Eastern Missouri Basin Power System
  - Basin Electric Cooperative
  - Bureau of Reclamation
  - Central Power Electric Coop.
  - Dakota Electric Coop.
  - Montana-Dakota Utilities Co.
  - Northern States Power Co. (Fargo, Grand Forks & Minot Divs.)
  - Northwestern Public Service Co.
  - Otter Tail Power Co. (Also Upper Miss. Valley Power Pool)

Northwest Interconnected Systems Group:
- Rocky Mountain Power Pool
  - Pacific Power & Light Co. (Wyoming Div.)
  - Black Hills Power & Light Co.
  - Cheyenne Light, Fuel & Power Co.
  - Consumers Public Power Dist. (Western Div.)
  - U.S. Bureau of Reclamation (USBR Reg. VII)
  - Tri-State Gen. & Trans. Assoc., Inc. (Transmission only)
  - Colorado Power Pool:
    - Public Service Co. of Colorado
    - City of Colorado Springs
    - Southern Colorado Power Co.
- Western Colorado Power System:
  - Western Colorado Power Co.
  - Colorado-Ute Electric Assoc., Inc.

PART F—PATTERN OF POWER SUPPLY—WEST SECTOR

The West Sector, as outlined in figure 110, constitutes roughly the western one-fourth of the United States, and accounts for about 19 percent of the country's electric load. It includes that portion of the contiguous United States generally west of the Rocky Mountains—corresponding with Coordination Study Areas N (Southwest) and P (Northwest), and FPC Regions VII and VIII.

Peak loads in the West Sector in 1962 were 28,000 megawatts. Projected peak requirements for 1970 are 50,000 megawatts and by 1980 the peak load in the sector is projected to be 94,000 megawatts, half as much as the nation's total today.

Load Distribution

The loads of Area N are concentrated around the San Francisco Bay area and the Los Angeles-San Diego (southern California) area. Central and northern California account for over 40 percent of the 1980 load in Area N, southern California about 45 percent, and the remainder of Area N (principally Reno and Las Vegas, Nevada, and Phoenix and Tucson, Arizona) account for somewhat over 15 percent. Total 1980 load in Area N is expected to approximate 54 million kilowatts.

In Area P, the State of Washington in total may account for around 52 percent of the 1980 load (half of which is in the Puget Sound area), and the State of Oregon around 31 percent, with the remainder distributed throughout the States of Idaho, Utah, and Montana. The total 1980 load in Area P is expected to approximate 40 million kilowatts.

The relative size of loads of the two study areas making up the West Sector is shown in the following tabulation of non-coincident Power Supply Area peak demands—actual for 1960 and 1962, and estimated for 1970 and 1980.

Actual and Estimated Loads in the West Sector (megawatts)

	1960	1962	1970	1980
Area N.....	13, 814	15, 888	28, 800	53, 880
Area P.....	10, 520	12, 007	21, 290	39, 870
Total..	24, 334	27, 895	50, 090	93, 750

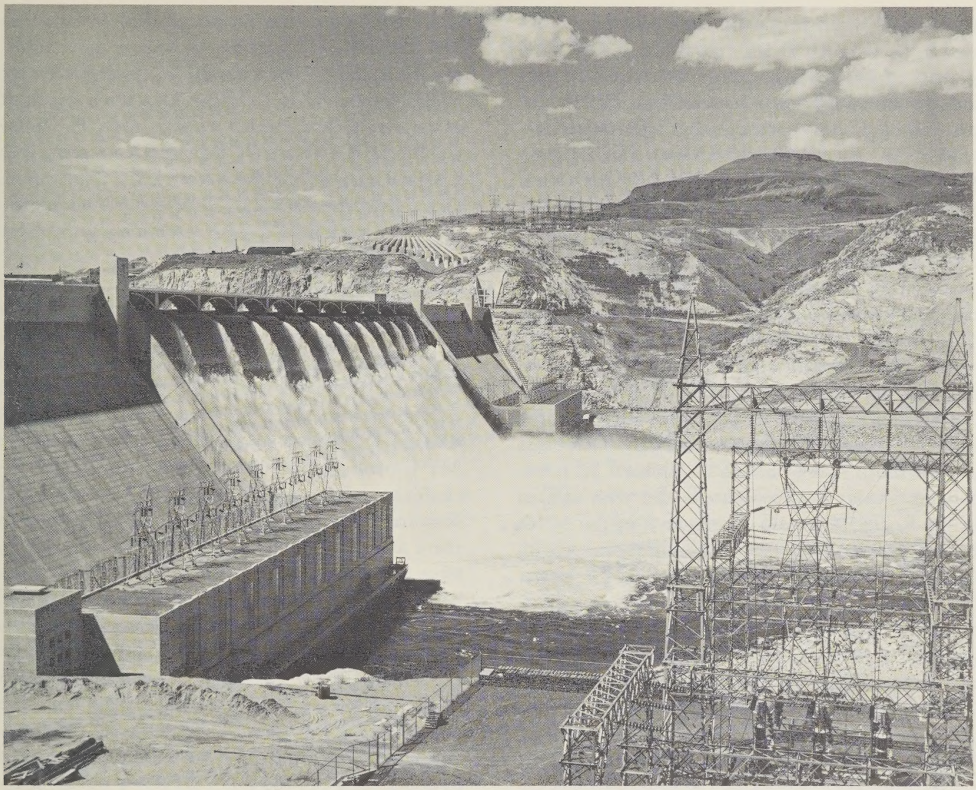

FIGURE 133 *Grand Coulee Dam is the largest Federal multiple purpose hydroelectric installation in the United States. It has a power installation of 1,944,000 kilowatts. Present plans envisage increasing its capacity to about 5½ million kilowatts.*

Operating Utilities

There are about 350 individual electric systems operating in the West Sector. Major utilities include local public agencies, investor-owned systems, and federal agencies. The Bonneville Power Administration markets the largest block of power in Area P and the Pacific Gas and Electric Company is the largest single company system in Area N, and in fact the largest investor-owned company in the United States. Rural electric cooperatives, public utility districts and municipal systems are well represented in the West Sector.

The 80 investor-owned systems in the West Sector provide 55 percent of the generation of electricity and make 61 percent of the retail sales. The Federal Government, municipals, and PUD's, totalling 183 systems, provide the remaining 45 percent of the generation and make 37 percent of the retail sales. The 88 cooperatives in the sector have practically no generation of their own and serve only two percent of the retail market.

Interconnected Operation and Power Pools

Utilities of the West Sector currently operate in separate and uncoordinated power pools.

The largest and the oldest of these separate pools is the Northwest Power Pool in Area P which was formed in 1942 at the urging of the War Production Board, and has since continued on a voluntary basis because of the benefits being attained. Under conditions prevailing in the early 1940's, capacity savings to the members of the Northwest

Power Pool through pooling were generally estimated to be as much as 600 megawatts. The effectiveness of the pooling operations and the magnitude of the savings have increased in the last few years through yearly coordination agreements succeeded by the Pacific Northwest Coordination Agreement executed in September 1964 for a term extending until June 30, 2003. Participants in this long-term coordination agreement are the Bonneville Power Administration, Corps of Engineers, five public utility districts, five investor-owned systems, three municipalities, and one transmission company. This agreement achieves electric and hydraulic optimization through coordinated forecasting, planning and operation. The members of the pool include utilities serving Washington, Oregon, Idaho, Montana, Utah, a small part of northern California and the south part of British Columbia. Its members are weakly intertied on the east with utilities in the Rocky Mountain Power Pool in the North Central Section, existing interconnections providing only a relatively small capability for power interchange.

Private utilities in Area N have, until recently, operated with relative independence of each other, and it was not until 1964 that the principal investor-owned systems in California completed a statewide pooling agreement which will become effective in 1966. At that time, the first sections of an ultimate 1,200 mile, 500-kilovolt network through California will be ready for service. Although major systems have operated in parallel, only limited coordination has been attained through bilateral contracts between neighboring systems. Interchange of power between the California and Arizona systems is not direct, but on a replacement basis by arrangement for use of power generated at the Federal plants on the Colorado River. The existing route of connection is from the Los Angeles area to the Hoover, Davis and Parker Dams to Phoenix, Arizona. During 1963, the Public Service Company of New Mexico built a 230-kilovolt tie to the Four Corners Plant of Arizona Public Service, thus tying the New Mexico Pool in Area M with the Arizona systems of Area N.

The Northwest Power Pool systems are predominantly hydro. Even under critical water conditions, the hydro plants can still generate the full requirements of the area, and under average water conditions, the projected 1965 installations can provide, in addition, secondary generation of about 20 billion kilowatt-hours annually, of which perhaps 12 to 15 billion kilowatt-hours must at present seek a market outside Area P. Since California is a relatively high fuel cost area, it is a logical market for the excess hydro generation. The construction of major EHV facilities to intertie these two regions is a most promising project for early development.

Transmission facilities throughout the Sector consist principally of lines of 230 and 287 kilovolts and lower, with only a few 345 kilovolt circuits. The only transmission ties from the Northwest to the east consist of a 161 kilovolt transmission link extending into Area L, and 230 kilovolt ties through Idaho into southwestern Wyoming. The 345 kilovolt transmission in the West Sector includes some BPA lines in the Pacific Northwest and lines from the Arizona Public Service mine-mouth plant at Four Corners to the Phoenix load center, some 300 miles distant. A 230 kilovolt connection between the New Mexico Power Pool (Area M) and Public Service Company of Arizona was recently put in operation. At present, only a very weak tie exists between Areas P and N, and synchronous operations of major California systems with the Northwest Power Pool has not been practical. Agencies of the Department of the Interior engaged in development of the Colorado River storage project are in the process of constructing a rather extensive 230 kilovolt transmission system in the Arizona, Colorado, and Utah areas of the project. These facilities will make substantial contributions to the high voltage network in rather sparsely settled areas of the West and will help in the formation of a high voltage grid involving Study Areas M, N, O, and P. They are illustrated on Figure 116. By means of these facilities, Flaming Gorge, Glen Canyon and Curecanti projects will be tied into existing networks to permit coordination with other projects on the lower reaches of the Colorado River and with sources of thermal generation. Such facilities will form a link at lower voltage between systems of large magnitude and may result in operating problems requiring either strengthening of such ties or operating with some of them open. This should be a point of further consideration and investigation in the long range planning of the utilities in the Mid-West and Western area.

TABLE 66

West Sector Power Pools

Northwest Interconnected Systems Group:

- Inter Company Pool:
  - Puget Sound Power & Light Co.
  - Pacific Power & Light Co.
  - Portland General Electric Co.
  - Washington Water Power Co.
- Puget Sound Utilities Council
  - Puget Sound Power & Light Co. (also in Northwest Power Pool)
  - City of Tacoma, Washington
  - Public Utility Dist. No. 1 of Chelan County
  - Public Utility Dist. No. 1 of Snohomish County
  - City of Seattle, Washington
- Bonneville Power Administration
- Idaho Power Company
- Utah Power & Light Company
- Montana Power Company
- U.S. Bureau of Reclamation
- U.S. Army Engineers
- City of Eugene, Oregon
- Public Utility Dist. No. 1 of Grant County
- British Columbia Hydro and Power Authority

Pacific Southwest Interconnected Systems Group:

- Pacific Southwest Power Interchange Committee:
  - California Power Pool:
    - Southern California Edison Company
    - Pacific Gas and Electric Company
    - San Diego Gas & Electric Company
  - Southern California Municipal Group
    - City of Los Angeles
    - City of Burbank
    - City of Glendale
    - City of Pasadena
  - U.S. Bureau of Reclamation
  - California Department of Water
  - Sacramento Utilities District
  - Imperial Irrigation District
  - Nevada Power Company
  - Sierra Pacific Power Company
  - Arizona Public Service Company
  - Salt River Project Agriculture Improvement & Power District
  - Colorado River Commission
  - Metropolitan Water District
  - Citizens Utilities Company
  - Tucson Gas, Electric Light and Power Co.
  - U.S. Bureau of Indian Affairs
  - City and County of San Francisco
  - Turlock & Modesto Irrigation Districts

There is now a relatively low voltage tie (161 kv) between the Northwest and the Missouri River Basin which is normally operated with switches open. Test closures have been made on a number of occasions but the capacity of the tie is too limited to permit continuous parallel operation. Available information indicates that coordinated operations of the hydro resources of the Pacific Northwest with those of the Missouri River Basin would result in a total increase in the dependable hydro resources of the two areas amounting to 400 megawatts. This increase results from the diversity in the frequency and duration of the critical water runoff periods in the two areas. To accomplish such coordination will require additional or strengthened ties between the two areas. A new tie which would increase the transfer capability between the two hydro resource areas, is proposed at 230 kilovolts between Yellowtail Dam and Glendive, Montana.

Present Generating and Transmission Facilities

The West Sector is characterized by its large resources of hydroelectric capacity and by the fact that areas of principal load concentration are distant from major fuel resources. In 1962, conventional hydroelectric capacity accounted for about 60 percent of the requirements in the West Sector. Nearly all of the remainder was supplied by thermal electric units, less than one percent being accounted for by diesels and gas turbines.

Load requirements in the Northwest now and through 1970 can be met for the most part with hydroelectric resources. It appears that thermal electric resources by 1970 will be generally limited to the 800 megawatt nuclear electric plant under construction at Hanford, Washington, and to energy imported from the coal-burning steam-electric plants in northern Utah and Wyoming, which are expected by 1970 to have an aggregate capacity of about 1,120 megawatts. While coal resources are available in the Cle Elum and the Centralia-Chehalis areas of Washington, and to a limited extent at a few other scattered locations in Washington and Oregon, major reserves within potentially economic distance are to be found principally in Eastern Montana (Area L), Wyoming and Colorado (Area O), and Utah (Area P) as shown on Figure 27 of chapter 3.

By 1980, it is projected that the power supply for the Northwest will include about 2,400 megawatts of conventional steam capacity (6.1 percent of total), and about 4,400 megawatts of nuclear capacity (11.1 percent of total).

In California (Area N), the rivers which drain the western slopes of the Sierra Nevada range in northern and central California have been extensively developed for hydroelectric power which in 1964 supplied 41 percent of the capacity utilized in that area. Further development of hydroelectric power is continuing, some of it by the State of California as a part of its major program for transporting water from the Northern California Rivers to Southern California. Thermal generation is fueled mainly by natural gas and oil which is and will continue for some time to be the predominant source for Area N.

Frequent atmospheric inversions which have intensified smog in the Southern California area, have resulted in local authorities imposing controls on the use of high sulphur fuels for thermal generation. This, together with the high cost of coal delivered to the California coastal areas, have been principal factors leading to the increased use of natural gas and more recently to including nuclear generation as part of the planned supply. Reserves of coal in Utah and in the Four Corners area of Northeast Arizona and Northwest New Mexico are the closest to major load centers in Area N.

Because of air pollution problems, no coal-fired thermal generation is likely to be installed in the vicinity of San Francisco, Los Angeles or San Diego. However, air pollution considerations should not preclude coal-fired thermal generation at coastal or other sites widely removed from these metropolitan centers, should this prove economic. Power supply to these major load centers from mine-mouth plants in the western coal fields is very much a possibility. However, at present, coal is expensive in California. This situation has resulted in increased interest in nuclear generation, although as of 1964, no nuclear capacity was operating in the region, except for two small experimental reactors.

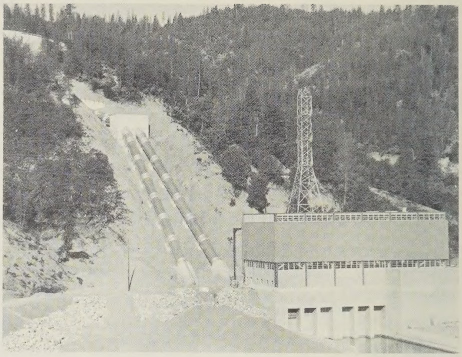

FIGURE 134 *Penstocks deliver discharge from Lewiston reservoir under 514 feet of head to the Clear Creek Power Plant of the Bureau of Reclamation's Central Valley Project in California.*

Approximately 60 percent of the total thermal capacity presently in service in the West Sector is represented by units of 100 to 400 megawatts size. The remaining 40 percent is represented by even smaller units. It is obvious that this region can effect large savings in the future by joint efforts that will enable all power systems to obtain power from larger and more economical generating units.

Programs for Early Development

Electric utility systems in the California-Arizona-Nevada portion of the West Sector (Area N) are constructing or planning to construct about 8600 megawatts of thermal generating capacity of which a minimum of 1200 megawatts is expected to be nuclear. In addition, some 3800 megawatts of hydroelectric capacity is currently under construction in Area N.

The 1200 megawatts of nuclear capacity would be supplied by 3 plants. The Los Angeles Department of Water and Power is moving forward on plans for construction of the Malibu Nuclear Plant of 463 megawatts at Corral Canyon, tentatively scheduled for operation in 1967. The Southern California Edison Company and San Diego Gas & Electric Company have joined in plans for the San Onofre Nuclear Generating Station of 375 megawatts at San Clemente to be completed in

1966. Study of a 325 megawatt nuclear plant by the Pacific Gas and Electric Co. for installation at Bodega Bay was recently dropped.

In Area P, there are no conventional steam plants planned for early development. However, 800,000 kilowatts of nuclear generation are being installed in the new Hanford plutonium reactor, scheduled for operation in 1965. Some 76 electric utilities have joined in sharing the output of this project. Under the terms of congressional authorization, 50 percent of the output has been made available to private utilities. Hydro capacity continues to be the primary source of power and approximately 4,500 megawatts is now under construction, the greater portion of which is in the following projects—John Day, Wanapum, and Wells on the main stem of the Columbia River, three projects on the Lower Snake River between the completed Ice Harbor project and Lewiston, Idaho and the Boundary Project on the Pend Oreille River in Washington.

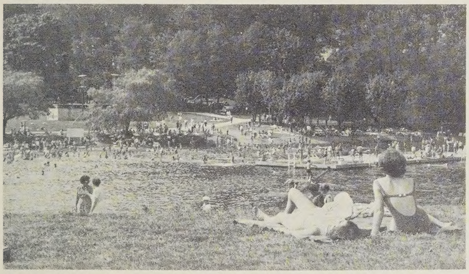

FIGURE 135 *The Merwin Hydroelectric Project on the Lewis River in southwest Washington under FPC license to the Pacific Power & Light Company, attracts nearly 75,000 persons annually to its picnicking and swimming areas. The project's recreation facilities can accommodate 5,000 persons.*

Two recent accomplishments will have significant impact on the future pattern of generation and pooling in the West Sector—these are the Treaty with Canada for the international development of the Columbia River which was implemented after ratification by both governments by an exchange of notes in September 1964, and secondly the approval by Congress in August 1964 of the Pacific Northwest-Pacific Southwest intertie program. Canadian storage and regulation will add approximately 2.8 million kilowatts of dependable hydroelectric capacity at downstream sites in the United States under adverse water conditions, and about 8 billion kilowatt-hours of average annual energy. Half of this amount belongs to Canada under treaty conditions, but under supplemental negotiations, the entitlement will be marketed in the United States for a period of 30 years. Since the Northwest area cannot utilize all of this power as soon as it becomes available, the logical market in the early years will be in the Pacific Southwest.

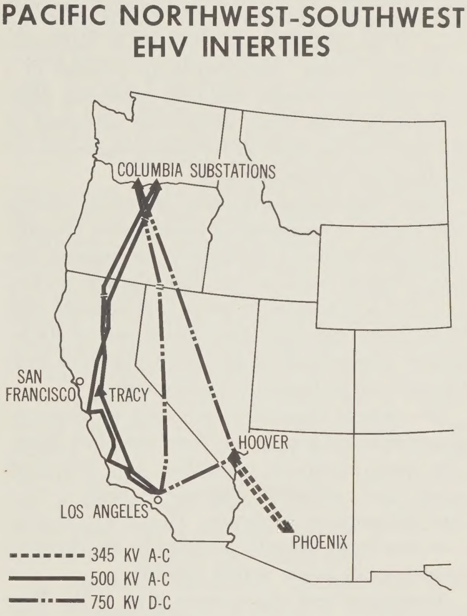

FIGURE 136

The intertie program constitutes an agreement reached between private, municipal, state and federal utilities for a vast transmission network intertying eleven western states, essentially Study Areas M, N, O, and P. Congress has appropriated initial funds for starting construction of the Federal portion of the interconnecting lines. The total plan calls for two 500 kilovolt AC tielines from the Columbia River to California, a 750[1] kilovolt DC line through Oregon and Nevada to Los Angeles, and a second 750 kilovolt DC line to Hoover Dam. The California Power Pool has planned two 500 kilovolt AC circuits from northern California to Los Angeles. From Hoover Dam, a 750 kilovolt DC line will connect to Los Angeles, and two 345 kilovolt AC lines will extend to Phoenix, Arizona.

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[1] ±375 kilovolts.

Over four million kilowatts of power will be carried between the two regions by these lines, with the first line to be completed in 1967 and the last in 1971.

Announcement was made in September 1964 of the formation of an association of eleven utilities [13] in the Southwest for the purpose of coordinated planning, construction and operation of generating and transmission facilities. The combined service areas of the group extend from lower California to El Paso, Texas. Included is the prospect of a very large mine-mouth, coal-fired generating plant in southern Utah which would take advantage of the Glen Canyon reservoir for cooling water and tap the large coal field in that area.

Other transmission facilities of special interest with regard to coordination programmed for early completion include a 345 kilovolt transmission line from Phoenix north to the Glen Canyon project. The line is scheduled to tie at 230 kilovolts with Utah Power and Light and with Bureau of Reclamation transmission from Glen Canyon to Four Corners and to Curecanti in Colorado.

The present situation with regard to power requirements and supply has been described above. The same factors of population and geography which have molded the past will continue to exert their influence on the future. However, this influence may be significantly modified by the changing technology in power supply facilities.

Population, and consequently load, in the West Sector is concentrated principally in the states bordering on the Pacific Coast. Fifteen hundred to 2000 miles separate this area of high load density from corresponding areas of high load density in the Mississippi River Valley and the Texas-Gulf Coast region. Coordination of utility planning is now progressing along the Pacific Coast, and in the future as economic opportunities arise, coordination can be achieved cross-country through long distance transmission ties with systems to the east and southeast. These possibilities are discussed in Section B of this chapter and a number of potential major interties are summarized in Table 59.

Vast reserves of coal of a good quality for power generation lie approximately midway between these widely separated areas of load concentration. With rapidly advancing technology in the construction of very large generating units and in EHV transmission, it is expected that the construction of large generating stations will become economically attractive in presently remote coal fields in Arizona, Wyoming, Utah, Colorado, and Montana. Such stations could be interconnected with the major power systems to the east and to the west by long distance EHV transmission lines which will in addition aid in coordination of systems of the West Sector with those to the east.

The extensive coal deposits in Wyoming, Utah and in Northern New Mexico near the "Four Corners" area contain deposits ranging in thermal quality from 10,000 to 12,000 btu per pound of coal. Most of the deposits appear to be adaptable to economic large scale strip mining production. Plants in the Cedar City area of Utah would require use of dry type cooling towers employing a closed circulating system to hold water consumption to a very minimum. As an alternative, plants might be located in the vicinity of Boulder City near the lower reaches of Lake Mead with coal conveyed by shuttle train from southwest Utah.

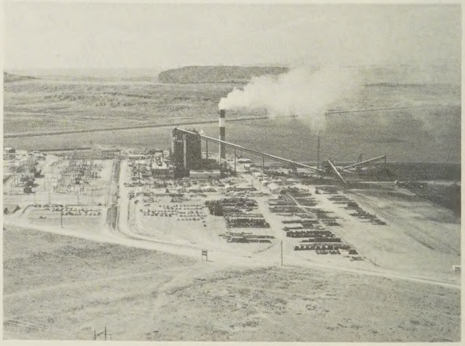

FIGURE 137 *The Four Corners Mine-mouth Power Plant of the Arizona Public Service Company has two 175,000 kilowatt units in operation and a third unit of 225,000 kilowatts nearly completed. Power from the plant is transmitted to Phoenix on two 345 kilovolt circuits.*

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[13] A recently announced group, Western Energy Supply and Transmission Associates (WEST Associates) includes Public Service Company of New Mexico, El Paso Electric Company, Public Service Company of Colorado, Utah Power & Light Company, Arizona Public Service Company, Tucson Gas & Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Sierra Pacific Power Company, and Nevada Power Company and the Los Angeles Department of Water and Power. Other southern California publicly owned systems may join.

The distance from coal resources to loads in the San Francisco and northern California areas is greater than to loads in southern California. The transmission distance from deposits in southwestern Utah to the Bay Area would be about 750 miles and from mines near Kemmerer, Wyoming, would be not less than 900 miles. Movement of bulk quantities of 2 to 3 million kilowatts of electric power from distant mines to loads, utilizing EHV direct or alternating current transmission, whichever is the most economic for this distance, would entail transmission costs in the range of 2.0 to 2.5 mills per kilowatt-hour based on the composite fixed charges used in the Survey for FPC Region VIII. A combination of moving coal by shuttle train to a plant near Reno, Nevada and transmission by EHV alternating current to San Francisco in comparable bulk quantities would entail comparable costs.

The construction of large amounts of nuclear power to supply loads in both southern and northern California appears very likely. Coastal locations are available, permitting development of large scale generating centers utilizing seawater for condensing and with access to water transportation for the shipment of large fabricated nuclear plant components. The absence of combustion products from these nuclear plants would avoid further contribution to atmospheric pollution.

At a greater distance in time, perhaps not until after 1980, large scale nuclear thermal generation in Southern California using advanced high conversion or proven breeder reactors in combination with evaporative desalination plants to produce fresh water supplies may afford an overall economic and beneficial development.

Many of the generating plants developed near load centers in California now utilize oil or natural gas in their generation of power. The outlook for capacity growth in California based on these fuels is regarded as only moderate as the cost of nuclear plants is reduced and development of EHV transmission brings in competition from distant sources of bulk generation.

The analysis of future transmission requirements for the West Sector must be made in consideration of two basic requirements—supplying the loads and providing interconnections to effect capacity savings from coordinated operations.

Reasonably strong internal transmission networks are in existence in both Areas P and N. To a large extent these networks result from the need to move major amounts of the supply from hydroelectric resources to load centers. With plans for increasing internal coordination, these networks are being strengthened. The transmission system of the Bonneville Power Administration is an outstanding example of a major transmission grid to coordinate all the facilities in a region.

As mentioned earlier in this section, there are no interties of any significance in existence between the Northwest and the Pacific Southwest and major savings will be realized from the new EHV/AC and DC North-South interties. Beginning benefits will accrue from delivery of surplus hydroelectric generation in Area P to replace thermal generation in Area N and transmission to the north of off-peak thermal-electric energy to firm up Northwest hydro capacity. The interties will carry for an interim period that part of the Columbia River power resulting from the Treaty with Canada which cannot be utilized initially in the Northwest. In addition, interchanges of seasonal diversity can be effected. An opportunity also exists, with a strong intertie between the two areas, for construction of as much as 4 million kilowatts of peaking capacity at hydroelectric developments in Area P for export to Area N along with 4.3 billion kilowatt-hours of surplus energy associated with this added capacity. The planned interties between Areas P and N will enable the transfer of a major portion of this capacity and in addition will enable substantial reductions in the total reserve capacity required in the two areas in the future as the systems grow.

As previously mentioned, arrangements have been consummated for a group of United States utilities to purchase for 30 years the Canadian entitlement of power which would be a product of the Columbia River Treaty and to market this power in the northwest. On this basis and assuming continued development of reasonably prospective hydroelectric opportunities in Area P, the growth in electric loads in this Area will be substantially satisfied until after 1975. There are many economic prospects for supplying the remaining needs of the Northwest until 1980. These include the consideration of nuclear power in major units located on the lower Columbia River and in the Puget Sound area, construction of a large generating plant in the area of the Cle Elum coal fields near Chehalis, Washington, bulk transport of coal by unit train from Cle Elum to several plants in the load areas along Puget Sound, and construction of major mine-mouth facilities at Kemmerer, Wyoming, with delivery to load centers in southern Idaho displacing power from Snake River sources which could then be moved north and west to Oregon and Washington load areas. Beyond 1980 with further devlopment and reduction in cost of long distance EHV transmission, power from Kemmerer might be delivered directly via EHV alternating current or direct current to a principal distribution point in the Northwest network.

One pattern of meeting the load requirements of 1980 in the West Sector premised on currently foreseeable trends and opportunities is summarized in Table 67. The rapid changes in the technologies of power production and transmission, and in methods and costs of fuel transport, portend the probability of many future adjustments in the relative economy of various types of generation. This is particularly true for the West Sector because the alternative opportunities are plentiful and many are closely competitive.

The load density patterns of Areas P and N and the distance between the areas and their location as related to the major load areas to the east all combine to require a much greater investment in interconnecting transmission facilities to obtain coordination benefits than for areas in the eastern half of the United States.

Summary for West Sector

Table 67 summarizes the sources of generation by general categories and for thermal plants by groups of unit sizes which have been included in the study of the general pattern for meeting the 1980 loads in the West Sector. The table includes existing generation expected to be retained for service through 1980. The general locations of new facilities assumed for 1980 are depicted on figure 116.

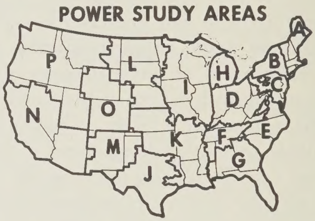

TABLE 67

West Sector

1980 Capacity Supply in Gigawatts

	Area N	Area P	West sector
Source of capacity:			
Diesel and gas turbine	0. 1	0. 1	0. 2
Conventional hydro	11. 9	32. 6	44. 5
Pumped storage	1. 0	0	1. 0
Steam-electric fossil fueled:			
0–400 mw units	17. 1	1. 0	[1] 18. 1
400–800 mw units	0. 8	1. 4	2. 2
800–1,200 mw units	6. 3	0	6. 3
1,200 and over mw units	4. 8	0	4. 8
Nuclear:			
0–400 mw units	0. 7	0. 8	1. 5
400–800 mw units	0. 6	1. 6	2. 2
800–1,200 mw units	7. 7	0. 8	8. 5
1,200 and over mw units	6. 5	1. 2	7. 7
Total capacity	57. 5	39. 5	97. 0
Percent distribution:			
Diesel and gas turbine	0. 2	0. 3	0. 2
Conventional hydro	20. 7	82. 5	45. 9
Pumped storage	1. 7	0	1. 0
Steam-electric fossil fueled	50. 4	6. 1	32. 4
Nuclear	27. 0	11. 1	20. 5

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[1] This consists of 120 units below 200 mw totaling 11.2 gw, of which 98 units totaling 8.9 gw were in service in 1960; and 25 units between 200–400 mw totaling 6.9 gw, of which only 5 totaling 1.2 gw were in service in 1960.

CHAPTER 16

POWER SUPPLY FOR SMALL SYSTEMS

The small systems in the electric power industry are understandably concerned about their future welfare as elements of the complex industry structure which serves America's electric consumers. They fear that the growing emphasis on the economies of scale in generation and transmission will reduce their opportunities for the orderly expansion of their own generating capacity, and perhaps even threaten their survival.

The interests of the small systems are a matter of vital concern in this National Power Survey. Small systems must recognize the need for obtaining their power supply from low cost sources and there must be opportunity for them to do so. Participation of the small systems in the benefits of coordination and a continuous search for means of broadening this participation are fundamental if these systems are to continue to provide low cost power to their consumers and make the most efficient use of our fuel and capital resources. Reduction in the costs of generation of the larger systems through more extensive adoption of the concepts discussed in the Survey can and must provide attractive sources of power for the use of the small systems, rather than serve as a threat to their existence.

We define "small systems" for purposes of this discussion, in order to provide a statistical breaking point, as those having annual energy production or requirements of less than 100 million kilowatt-hours. The definition is necessarily arbitrary. Assuming an annual load factor in the range of 45 percent, the definition would represent a system with peak load requirements of about 25,000 kilowatts or less. While the small systems are mainly municipal systems or rural electric cooperatives, they also include almost 300 small investor-owned systems.

Table 68 summarizes the "principal" and "small" systems by FPC statistical region and by ownership. The table shows that of the total of 3,617 systems serving the country (excluding Alaska

TABLE 68

Number of U.S.[1] Electric Utility Systems by Size, Geographic Distribution and Ownership as of December 31, 1962

Region	Number and distribution of principal electric utility systems [2]				Number and distribution of small electric utility systems [2]				Total number of systems—large and small
	Investor-owned	Publicly owned	Cooperatives	Total	Investor-owned	Publicly owned	Cooperatives	Total	
I—Northeast	47	9	1	57	70	188	27	285	342
II—East Central	24	10	3	37	23	261	106	390	427
III—Southeast	17	61	29	107	18	272	166	456	563
IV—North Central	34	8	10	52	52	478	195	725	777
V—South Central	32	22	11	65	51	370	209	630	695
VI—West Central	13	8	7	28	21	298	117	436	464
VII—Northwest	15	27	3	45	21	94	70	185	230
VIII—Southwest	9	26	1	36	33	36	14	83	119
Total	191	171	65	427	289	1,997	904	3,190	3,617

[1] Excludes Alaska and Hawaii.

[2] Principal systems are defined as Class I systems with net energy for system of more than 100,000,000 Kilowatt-hours per year, and Class IV systems with either net energy for system or net energy for load or net generation of more than 100,000,000 Kilowatt-hours per year. All other systems are listed in the small electric utility system group.

and Hawaii), 3,190 are small systems of which 289 are investor-owned, 1,997 are publicly owned (principally municipalities), and 904 are rural electric cooperatives. It can be seen that for the nation as a whole the investor-owned group includes the largest number of "principal" systems and the public-cooperative group heavily dominates the small systems category. However, there are marked regional variations. For example, while in the Northeast almost 84 percent by number of the principal systems are investor-owned, in the Southeast, the Southwest and the Northwest over two-thirds of the principal systems are in the public-cooperative group. This does not mean, of course, that the public-cooperative group accounts for two-thirds of the business in these areas.

Most of the largest enterprises are in the investor-owned category, although TVA, Bonneville and the Los Angeles municipal system also rank at or near the top in size. Nationwide, the small systems account for about 15 percent of total retail sales but for less than 3 percent of generating capacity. About one-third of all of the publicly owned systems in the country are located in five states: Nebraska, Kansas, Iowa, Minnesota and Ohio, each of which has 100 or more of such systems.

Table 69 classifies the small systems by size, ownership and source of power. The table shows that 28 percent generate all or part of their requirements, while 69 percent purchase their entire needs. The remaining 3 percent are engaged primarily in sales for resale or sales to industrials. Here again there are notable variations from one ownership class to another. Thus almost 95 percent of the small cooperatives purchase their entire requirements, while only about 50 percent of the small investor-owned systems and 60 percent of the small municipalities do so.

Rural Electric Cooperatives

The rural electric cooperative systems which were almost all created after passage of the Rural Elec-

TABLE 69

Number and Size of Small Electric Utility Systems in the U.S.[1] as of December 31, 1962

1962 Kwh output (Millions)	Number of systems by ownership					Total	
	Investor-owned	Municipal	Federal	Other public[2]	Cooperatives	Number	Percent
Systems generating all or part of their requirements							
20 to 100	28	170	2	7	19	226	7.1
5 to 20	22	286	1	8	17	334	10.5
Less than 5	41	286	4	......	8	339	10.6
Subtotal	91	742	7	15	44	899	28.2
Systems purchasing their entire requirements							
20 to 100	33	234	......	24	531	822	25.8
5 to 20	37	326	1	22	260	646	20.3
Less than 5	79	570	1	3	64	717	22.4
Subtotal	149	1,130	2	49	855	2,185	68.5
Systems engaged primarily in sales for resale or sales to industrials							
20 to 100	14	5	17	11	3	50	1.6
5 to 20	6	7	2	1	1	17	0.5
Less than 5	29	8	1	......	1	39	1.2
Subtotal	49	20	20	12	5	106	3.3
Grand totals	289	1,892	29	76	904	3,190	100.0

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[1] Excludes Alaska and Hawaii.

[2] Includes state authorities, irrigation districts, utility districts, etc.

trification Act of 1936 numbered 969 individual systems as of December 31, 1962. Over 90 percent of this number fell within the category of small systems as we have classified them.

The remarkable growth of the electric cooperative movement is familiar recent history. When the REA was established in the mid 30's, only about 10 percent of the country's farms had central station electric service. Today we are approaching 100 percent rural electrification, of which the cooperatives account for about half. The geographic coverage of the rural electric areas of the nation is depicted in Figure 12, pp. 20 and 21.

The energy requirements of the cooperatives have been increasing at a phenomenal rate. During the period from 1950 through 1962 the energy sales of this group increased more than fourfold from 6.9 to 31.9 billion kilowatt-hours. Their compound rate of growth in this period of about 13 percent per year compares with a compound rate of about 8.0 percent for investor-owned utilities. In part, this rapid growth reflects the great movement to the suburban and formerly rural areas that has characterized the post-war period. The number of active farms in the same period actually declined from about 5.5 million to 3.5 million.

In Table 70 the total energy requirements of all cooperatives are compared with total U.S. requirements at intervals from 1945 to 1962. During these years the cooperatives' share of total requirements has steadily increased from 1.09 percent in 1945 to 4.25 percent in 1962. They now serve 8.0 percent of the nation's ultimate consumers.

TABLE 70

Electricity Requirements for Selected Years 1945 to 1962

(Millions of kwh)

Year	Cooperatives	Total U.S.[1]	Cooperatives as percent of total
1945.........	2, 417	222, 486	1. 09
1950.........	8, 347	329, 141	2. 54
1955.........	18, 250	547, 038	3. 34
1960.........	30, 978	753, 350	4. 11
1962.........	36, 177	852, 314	4. 25

[1] Represents total generation for years indicated, excluding Alaska and Hawaii.

The cooperatives, including the G&T cooperatives, generate only about 18 percent of their own energy requirements, and while this percentage is increasing it is still less than one percent of total U.S. generation as compared with the cooperatives retail sales of over four percent of the U.S. total. In fact the cooperatives as a group generate a smaller percentage of the power they sell to ultimate consumers than any other major segment of the industry.

For the most part the energy requirements of the cooperatives are supplied by the larger public and investor-owned power suppliers. In 1963 cooperatives purchased 82 percent of their power supply at wholesale. Table 71 shows the sources of their power supplies for selected years from 1950 through 1963.

TABLE 71

Sources of Power Supply of Cooperatives in Percentages of Total for Selected Years—1950 to 1963

		Purchases			
Year	Self generation	Federal agencies	Other public agencies	Investor-owned utilities (incl. industrial)	Total purchases
1950....................	13	24	9	54	87
1952....................	14	28	8	50	86
1954....................	15	31	8	46	85
1956....................	17	34	8	41	83
1958....................	15	39	7	39	85
1960....................	16	39	7	38	84
1962....................	16	39	7	38	84
1963....................	18	37	7	38	82

As is evident from this tabulation, the portion of the cooperatives' power supply needs provided by Federal agencies increased rapidly from 24 percent in 1950 to 39 percent in 1958. This increase was paralleled by a reduction in the proportion supplied by investor-owned companies, which fell from 54 to 39 percent during the same period. The proportions of power supplied to the cooperatives by these two groups have remained almost constant and practically equal since 1958. Self generation by the cooperatives as a proportion of their total requirements gradually increased from 13 percent in 1950 to 17 percent in 1956, but has since remained fairly constant, increasing to 18 percent in 1963. New plants authorized and under construction will result in some increase in this percentage.

The cooperatives have maintained and slightly increased the proportion of their total requirements produced by their own generation in the face of their rapidly expanding need for power primarily by joining together in generating and transmission cooperatives, the so-called "G&T's". Of the 20 or more states which now have G&T's, the larger suppliers are developing in Wisconsin, North Dakota, Iowa and Missouri. In the latter two states, each of which has five G&T's, a large percentage of the distribution cooperatives hold membership in and receive their energy supplies from the G&T's. In many instances these supplies are supplemented by power from Federal systems and from investor-owned utilities.

Generating units installed by the G&T's have generally been small as steam-electric units go. However, several units in the range from 100 to 200 megawatts are under construction or are being planned, and in the case of a group of Ohio cooperatives, a 615 megawatts unit is planned for coordinated operation with investor-owned utilities. As cooperative loads increase, a gradual increase in size and efficiency of generating units will logically follow. This trend can be accelerated by interconnecting and coordinating systems into larger operating groups or pools and optimizing the power supply for the group.

Municipal Systems

Municipally-owned systems constitute the other large group in the small systems category. The small municipal systems are numerous, and they supply almost 10 percent of the needs of the ultimate consumers of the country. Table 69 shows that of the 1892 small municipal systems that were operating in 1962, 1483 had requirements or output of less than 20 million kilowatt-hours which at 45 percent load factor would mean a peak load of 5,000 kilowatts or less. As is also indicated in Table 69, 742 of the small municipal systems generated all or part of their requirements in 1962, while the remaining 1130 systems purchased their entire requirements.

The number of municipal systems has been relatively stable in recent years. Systems in operation in 1927 numbered nearly 2200, ten years later the number had declined to about 1900, and except for minor ups and downs has changed relatively little to date. At the end of 1962 about 2000 municipal systems were in existence.

Detailed statistics concerning the physical and financial operations of most of the smaller municipal systems are not reported to the Federal Power Commission. The lack of data concerning the operations of municipal systems has been a handicap both to these utilities and to analysts who assist them in expansion or improvement studies. The Commission in recent years has simplified its reporting forms for municipalities and is encouraging all municipalities to complete them.

Small Investor-Owned Companies

While the vast majority of small systems fall in the general category of public or cooperative power, it would be a mistake to assume that all investor-owned power companies are large. Spread throughout the country are some 289 small systems that are investor-owned. A significant number of them, 70, are located in the northeast. Their number has been gradually decreasing over the years due primarily to consolidations with or acquisitions by the larger investor-owned systems. In 1960 there were 309, twenty more than were in existence at the end of 1962.

These 289 small investor-owned systems outnumber the 191 major investor-owned companies but own less than one percent of the nation's generating capacity while the large investor-owned companies account for nearly 80 percent of the total. The 149 small investor-owned companies that are solely distributors of power purchase their power supply primarily from investor-owned companies although a few buy from the Federal power agencies, G&T cooperatives and municipalities. The small investor-owned companies account for less than five percent of the total energy sold to ultimate consumers.

Power Sources

Some small systems generate their entire power requirements from generating stations operated in isolation from other systems in the area. However, the majority of small systems are interconnected with neighboring systems and obtain all or part of their power supplies from other systems under a wide variety of purchase and interconnection agreements. Some situations representative of these patterns are described briefly below.

The purchase of full power requirements at wholesale from either an investor-owned utility or a Federal marketing agency is a typical power supply arrangement for small municipal and cooperative systems throughout the nation. For example, substantially all of the public power distributors in the TVA service area purchase their entire power requirements at wholesale from TVA.[1] TVA provides all new generation needs and transmission facilities and delivers the power to the load centers of these distributors. It has assumed a "public utility" responsibility for its service area. Its wholesale customers include 102 municipalities, 51 rural cooperatives and two small investor-owned utilities.

Many municipal systems purchase power at wholesale from investor-owned utilities. In fact there are over 900 such municipalities throughout the nation, primarily in areas where federally marketed power is not available, who rely on investor-owned companies for all or part of their power supply.

In the Missouri Basin, power from Federal hydroelectric projects is broadly distributed by the Bureau of Reclamation to preference customers in an eight-state area. Some 250 wholesale customers are served, many of which are small municipal systems or cooperative distributors. They receive their power supplies directly from the extensive transmission network of the marketing agency or by wheeling arrangements with investor-owned utilities and REA financed G&T's. These customers and the Bureau have become associated in the Missouri Basin Systems Group. This pooling arrangement will permit the development of future supplies from much larger, more efficient generating units than if attempted by smaller groups or individual purchasers. The first step in this direction is by a 200 megawatt lignite-fueled thermal plant at Stanton, North Dakota, being constructed by the Basin Electric Power Cooperative.

Except for the Federal grid in the western part of the State, the transmission network in Nebraska is a publicly owned system, operated by agencies of the State. All municipalities are served by public utility districts and the rural areas are served by cooperatives. Nearly all generation is supplied to the various municipal and cooperative distributors in the State by several of the larger public power districts. The districts are interconnected by the public grid which for the most part operates at 115 kilovolts.

In some parts of the country, small systems are still operating as individual entities with little or no association with other utilities for beneficial exchanges or reserve support. Many municipalities operate generating facilities that are not interconnected with others, often because of legal impediments, and as a result their plants are small and inefficient by modern standards. For example, of the 137 municipal systems operating in Kansas in 1962, 60 generated their entire requirements and 55 of the 60 were completely isolated from any other electric system.

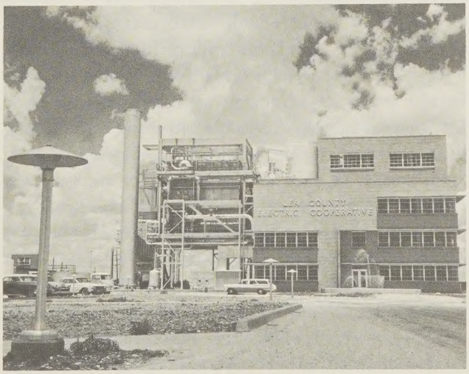

FIGURE 138 *This natural gas fueled, 22,000 kilowatt steam-electric plant of Lea County (N.M.) Electric Cooperative completed in 1962, was the main supply for the utility's 32,400 kilowatt load in 1963. This cooperative also has 20,100 kilowatts of internal combustion capacity, and has a 115 kilovolt interconnection with Southwestern Public Service Company.*

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[1] Memphis at present has its own generation. Under agreements already executed, after 1965 it will transfer its plant to the TVA under a lease-purchase arrangement and then purchase all of its power from the TVA.

Nearly all of the 77 other municipal systems purchase their entire requirements at wholesale, mostly from investor-owned companies, but several are served by a cooperative.

At the present time all power supplies for rural cooperatives in Ohio are purchased from investor-owned utilities. However, as described in Chapter 15, work is under way on the construction of a large two-unit steam-electric central station jointly owned by the American Electric Power system and Buckeye Power, Inc., a G&T cooperative which, uniquely, plans to rely on private rather than REA financing. The Buckeye unit will supply power to a group of 30 cooperatives in the state via transmission facilities of the AEP system and other interconnected companies.

The Performance of Small Systems

Fundamental technological and operating factors make it necessary to distinguish between the distribution and production functions in evaluating the performance of small systems.

The electric power industry is inherently capital intensive. There are large economies of scale in production—i.e., generation and transmission. Economies on the distribution side, however, are keyed to high usage per consumer and high consumer density per mile of line.

Because of these inherent characteristics of the industry the small electric systems are at an economic disadvantage in the production of power. Other things being equal, small plants cost more per kilowatt to build, burn more fuel per kilowatt hour, cost more per kilowatt hour to operate, and require much larger percentages of reserve capacity for emergencies when operated in isolation. Nevertheless, it does not necessarily follow that economic logic would dictate abandonment of all or even most of the generating equipment of the small systems. Of course, in planning additions to existing plants or new generating facilities, a comparison with purchased power must include all of the costs of self-generation, but where the equipment has already been installed, the investment costs are largely sunk, i.e., non-recoverable except for salvage value, regardless of whether the equipment continues to be used to generate power. In the decision as to whether self-generation or purchase at wholesale would be more advantageous, such costs, for the remaining useful life of the equipment, cannot properly be included among the production costs. Rather, the comparison must be made between the incremental cost of self-generation and the total payments for purchased power, which normally includes an appropriate share of the fixed costs of the supplier.

The economic position of many of the small systems is related in part to the benefits or advantages of their institutional status. For example, municipalities can in many instances borrow at low interest rates because the interest received by the holders of municipal bonds is exempt from the Federal income tax and municipal plants commonly pay no property or income taxes as such although many pay substantial sums in lieu of taxes in support of local government. From the point of view of the individual municipality these factors are of vital importance in weighing the relative benefits and costs of self-generation versus purchase at wholesale. These advantages for municipal generation may offset a considerable difference in efficiency as compared with alternative power sources.

Although there are inherent economic disadvantages in self-generation by the small systems, using small units operating in isolation, no comparable disadvantage is inherent in their performance of the distribution function. The small distributor may be able to distribute energy fully as economically as a large utility. This is especially true where a low rate policy enables the small system to build up high average use per consumer and high customer density per mile of line, which in turn result in lower unit costs. A good illustration is the experience of TVA's municipal and cooperative distributors, where even the smaller distribution systems have demonstrated that they can perform the distribution function on an economical basis.

The small and large systems each have certain advantages in distribution which may be reasonably offsetting. For example, small municipal systems are often able to realize economies by combined electric and water meter reading and billing, and by sharing the services of certain municipal officials and clerical personnel. Overhead costs may be lower for small systems, and management is closer to the consumer level. The countervailing benefits of the large systems include better workload factors for maintenance crews, more specialized equipment and personnel, better executive and technical supervision, and the ability to mobilize greater resources for restoration of service in emergencies.

Clearly, small systems costs do not compare as favorably in production as in distribution. The cost gap between small-scale and large-scale production of electric energy is being progressively widened by technological change. Pooling and coordination with other power generating systems is essential to economical generation by the small systems. Small systems can reap large benefits from even moderate increases in unit sizes. The percentage advantage of moving, for example, from 25 to 50 megawatt units is far greater than escalating from the 250 megawatts to the 500 megawatts range. (This is not to minimize the importance of taking full advantage of scale.)

The continued reliance on small and isolated generating plants by many small systems in the past was not without reason. In many cases lower-cost power may not have been available from any other source, either because the other sources were also high-cost, or because the wholesale rates did not reflect a full share of the economies of efficient generation. In other cases the small systems may have willingly paid a small penalty for self-generation in the belief that independence in generation was the price of survival.

A major purpose of the National Power Survey is to suggest alternatives to small and inefficient generating plants which will permit the small distribution systems to persevere and prosper by sharing in a power supply from large-scale, low-cost sources on reasonable terms and with assurance of adequate supply for future expansion.

Some municipalities and cooperatives of course can buy energy at low wholesale rates from Federal or state power marketing agencies, but this service is not available to many hundreds of distributors. Other small systems may join together to achieve low wholesale power costs by cooperating in building generating plants although, as the Legal Advisory Committee Report points out, this avenue may be currently barred in some states by legal obstacles such as statutory restrictions on municipal borrowing and on inter-governmental agreements.

Many small systems have been restricted to a choice between generating their own power and buying it at wholesale from one of the large integrated investor-owned systems. Left to this choice, and sensitive to the history of friction between the public and private segments of the industry, some municipalities and cooperatives have preferred to build their own generating plants at higher cost rather than to obtain power from sellers who are potential (or active) competitors. The absence of consistently effective regulatory surveillance of wholesale power contracts has contributed in the past to these limited choices by small electric systems. Most wholesale sales of electricity to distributors are made in interstate commerce and jurisdiction over such sales is lodged with the Federal Power Commission. If the Commission in the past has not fully implemented its authority, the failure is one which it is now attempting to redress.

The recent expansion of the FPC's electric rate regulation staff, the Commission's intensified interest in wholesale rate regulation and the recent clarification by the Supreme Court in the *Colton* decision[2] of the scope of the Commission's wholesale rate jurisdiction, offer promise of effective regulation for the future. Effective regulation would mean that the small distributor need not accept excessive rate levels or agree to unfair contract terms. Such a distributor could buy power at wholesale in the reasonable expectation that the seller would recognize his right to exist, would not invade his territory, would share fairly the economies of low cost power sources, and would cooperate in meeting the purchaser's long-term load growth. The small system would have assurance that a wholesale power contract with a large neighboring system would not impair its competitive position. Given the assurance of an impartial forum, the small distributor could explore wholesale purchases as a future power supply source with confidence, and a more rational power supply structure would be within reach.

Economic Improvement Opportunities for Small Systems

Much of this report has dealt with the larger systems which constitute the bulk of the nation's electric power industry. In this chapter some of the opportunities available to the smaller utilities are further examined and evaluated. In none of these suggestions are we proposing to alter the relative balance among the various segments of the industry. It may well be that some adjustments of ownership would be fruitful or that some consolidations within the ranks of a particular segment would be economically advantageous, but we do not here address ourselves to these questions.

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[2] F.P.C. v. Southern California Edison Co., 376 U.S. 205 (1964).

Opportunities for greater coordination and intersystem enterprise for the smaller systems are abundant. As we have noted, the economy in generation achieved by doubling the size of units in the 25 to 50 megawatt range is greater than in the range of 250 to 500 megawatts. Similarly, where two or three generating units form the basis of a system's supply the reduction in system reserves made possible by interconnections is greater percentagewise than the reduction attained by interconnecting larger systems where each has 20 or 30 units available. The opportunities for lower power costs in the future are thus just as promising for the small systems as for the large ones.

A number of the smaller systems have made and are making large improvements in unit costs. The following describes some of the methods they have followed.

(a) Sharing with one or more large systems in the joint construction of larger and more efficient generating facilities. This alternative may be impracticable for a small isolated system, but not for a group of systems working together. The Buckeye project in Ohio, in which all of the cooperatives in the state have joined, in participation with a large private company, is an outstanding example of this approach.

(b) Interconnecting among themselves to provide emergency backup in order to reduce the capacity required for reserves. Such interconnections can effect large savings because it is common practice—in fact essential practice—among independent small systems to have reserve capacity at least equal to the capability of the largest generating unit. With only two units, therefore, a minimum of 50 percent reserve is required, perhaps three or four times the reserve requirements of larger systems. Interconnections can also enable the small systems to build larger and more efficient units by combining in joint projects to meet their combined load growth or to stagger the individual construction of larger units on a share-the-capacity basis. Also, improvement in the combined load factor frequently results from interconnecting a number of systems. For example, five or six small utilities which individually have an annual load factor of say, 45 percent, might well experience an interconnected load factor three to five percent higher. Where transmission capacity is available on local networks, interconnections with other small systems through wheeling arrangements might be a feasible alternative to constructing new lines. G&T cooperatives are serving many municipalities, in whole or in part, by utilizing the transmission systems of local cooperative distributors.

(c) Participating with larger systems as members of a power pool whether or not the other members of the pool belong to the same industry segment.

(d) Securing wholesale supply service at reasonable prices and on fair terms either through negotiations for an interconnection with available suppliers or, upon application, by order of the Federal Power Commission.[3]

(e) Obtaining reductions in wholesale rates where they are excessive through negotiations or through proceedings before the Federal Power Commission under its authority to regulate the wholesale rates of interstate suppliers pursuant to the Federal Power Act.

(f) Seeking service from a Federal or public supply system offering lower cost power if the utility is entitled to preference and is within the normal service area of such suppliers.

(g) Improving operating performance through employment of qualified engineers, accountants and other specialists, either individually or through a joint group or trade association. Long range plans are needed, and accurate cost records are essential.

(h) Merging with other utilities may be the only solution where the enterprise is handicapped by lack of financial or technological resources for growth or by other serious limiting conditions. Mergers may also be desirable in other cases.

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[3] Section 202(b) of the Federal Power Act provides: "Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided,* That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them."

Impediments to Growth and Improvement

There are few physical or economic obstacles in the way of small system growth and improvement, but legal and psychological barriers must be considered. The principal legal barriers are the restrictions applicable to public bodies that were documented by the report of the Legal Advisory Committee and summarized at the beginning of Chapter VII of that report as follows:

> The legal authority of local public agencies to enter into interconnection and pooling agreements, leasing arrangements and joint ventures, including the creation of jointly owned entities to construct new facilities, is limited in various respects which sometimes prevent entirely, and sometimes substantially affect the nature of, proposed pooling arrangements.[4]

So long as these restrictions remain in the law they will retard the efforts of the municipalities and other local public systems to achieve service areas that are reasonable operating entities, to build generating plants and transmission lines according to the dictates of economy and business prudence, and to participate fully in the integrated planning and operating networks which increasingly characterize the American power economy.

Psychological barriers also stand in the way of full coordination between the small municipal and cooperative systems and the investor-owned systems. These barriers are the fruit of decades of intra-industry animosities, and they impair many opportunities for small system improvement. Because of their distrust the municipalities and cooperatives are often hesitant to sacrifice any of their autonomy by purchasing power from investor-owned systems or engaging in joint projects with them regardless of the prospect of large economies.

Overcoming these barriers is an important goal for the entire industry, but it will not be easy to attain. Determined and resourceful leadership in all branches of the industry will be required. The Federal Power Commission is attempting to contribute to the elimination of these obstacles by the effective and impartial regulation of wholesale electric rates and the terms and conditions of service for transactions in interstate commerce.

Where economic strength alone determines bargaining power, the small systems may be at a great disadvantage, but where regulation is effective, long-term wholesale relationships can be built firmly on a foundation of legally-enforced rights and responsibilities. With such a foundation the parties are enabled to reach the most economic solution to the problem of power supply under the particular circumstances of each case.

Conclusion

The opportunities discussed in this Chapter resemble in many respects those available to larger systems through joint participation and interconnection. Although the facilities involved may be only a small portion of those of the larger systems, the percentage reduction in power costs resulting from interconnection of small systems may be greater than for large systems. We are convinced that interconnection and coordination of all utilities, large and small, is achievable by 1980. We are also convinced that there is a growing trend throughout the nation toward more friendly cooperation among governmental units and private businesses in performing common functions. The small systems, as well as the large, will benefit by lending their weight and influence in this direction.

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[4] Advisory Committee Report No. 22, p. 377 of Part II.

CHAPTER 17

OUTLOOK FOR COST REDUCTIONS

The final consideration in the survey, and the one of greatest significance to the industry and consumers, is the influence of the projected trends and suggested patterns on the price of electricity in the future. The numerous factors that have a bearing, directly or indirectly, on the cost of furnishing electric service have been covered in earlier chapters. While these factors cover a broad interrelated front, they can be grouped generally into five principal categories.

- The projected generous growth of future loads as discussed in Chapter 2 and the accompanying large increase in use per customer is undoubtedly one of the most important factors.
- A second is the vast array of current and potential improvements in the facilities of the industry. The trends and improvements in generation are presented in Chapters 4 through 9 and in transmission and distribution in Chapters 10 and 11.
- The cost of fuels for generation, which account for about 15 percent of the total delivered cost to the consumer of steam generated electric energy, is another element of much importance. The future availability of the various fuels and the probable trends in their cost are summarized in Chapter 3.
- The fourth category concerns the savings that can result from a sweeping extension in the coordination of system planning, construction and operation, particularly with respect to generation and transmission facilities. These are extensively analyzed in Chapters 12, 13 and 14 and a possible pattern of future generation and transmission is presented in Chapter 15 and for small systems in Chapter 16.
- The last category includes reductions in the price of power that can be effected by reducing the costs of financing and from recently lowered Federal income tax requirements.

In this concluding chapter, we seek to estimate the average price of electric energy for the period around 1980, to relate this projected price to price trends in recent decades, and to appraise the general magnitude of the principal factors affecting cost reductions.

Suggested Target for 1980

The estimated price for power achievable by 1980 is premised on the magnitude of plant investment and operating costs to be expected in that year, founded on the general pattern of generation and transmission presented in Chapter 15. Basic fiscal assumptions underlying these estimates are outlined in a later paragraph.

The study reveals that a reduction can be expected in the nationwide average price per kilowatt-hour from about 1.7 cents today to about 1.2 cents in 1980.[1] This is an average price for all ultimate power sales including residential, commercial and industrial.

This target should not be interpreted as the result of precise forecasts but rather as an estimate based on various assumptions regarding future developments, some of which are not within the industry's control and are difficult to predict with confidence. Nevertheless, we believe that the goal of 1.2 cent power by 1980 is within the industry's reach. It is consistent with the industry's history of accomplishment, particularly since 1940, with the expected continuing evolution of technology, and the latent economies of scale that can accompany the increased loads and higher use per customer.

In presenting a target for the industry's future planning, we recognize that it will need to be reviewed from time to time on the basis of later information regarding current trends and future prospects.

How these reductions are related to the principal components in the cost of power is shown in Table 72. In brief, we estimate that the generation component will be reduced 26 percent and distribution 35 percent. The cost of transmission per kilowatt-hour will remain the same as it is today, because of the numerous added major transmission interconnections between systems, areas and regions, but these new transmission facilities help to make possible the reduction in generating costs.

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[1] 1.68¢ and 1.23¢ before rounding as shown in table 72.

TABLE 72

Component Costs of Power Supply[1]

(Per Kilowatt-hour)

	Actual 1962	Per-cent of total	1980 Projected	Per-cent of total	Reduction	Per-cent-age reduc-tion
Generation	0.85 cents/kwh	51	0.63 cents/kwh	51	0.22 cents/kwh	26
Transmission	.17 cents/kwh	10	.17 cents/kwh	14		
Distribution	.66 cents/kwh	39	.43 cents/kwh	35	.23 cents/kwh	35
Total	1.68	100	1.23	100	0.45	27

[1] Costs such as administrative and general expenses and the annual fixed charges on "General" plant, not directly assignable to these three components, have been allocated thereto on the basis of proportion of direct costs.

Past Price and Rate Trends

A review of past trends in the delivered price of electricity provides an encouraging point of departure for our discussion of an attainable target for the industry in the future. As depicted in figures 139 and 140, the ultimate consumers of electricity in 1926 paid an average of 2.7 cents a kilowatt-hour. By 1940 this figure had been reduced to 2.1 cents. Notwithstanding the ensuing wartime and postwar price inflation, by 1950 the average price had declined to 1.8 cents. The 1950's were characterized by further inflation, and the exceedingly rapid expansion of the industry's capacity. Even so, by 1960 the average price to consumers had fallen to about 1.69 cents, and in 1962, it was 1.68 cents a kilowatt-hour, about 40 percent below the average price in 1926.

The dominant factor in these declines in the price of electricity is the increase in the per capita consumption of electricity, with the accompanying increased efficiency in its generation, transmission and distribution.

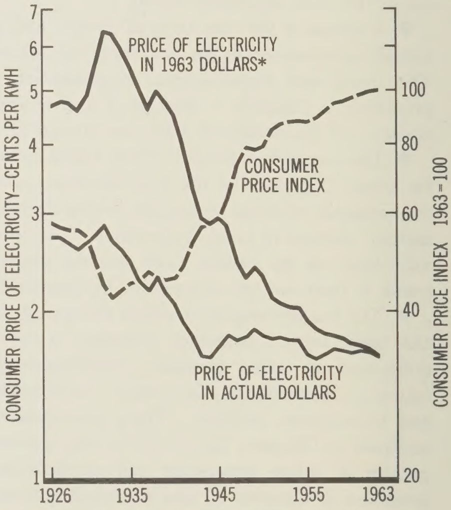
Under the block system of rates almost universally employed in the United States, the cost of electricity per kwh automatically goes down with increased usage because a greater proportion of the use is in the lower-priced rate blocks. Thus the average price to the consumer per kilowatt-hour declined during the decade of the 1950's because of increased consumption even though during that period rates actually were slightly increased.

The price inflation during and after World War II exerted strong upward pressures on costs of production throughout the economy, but these pressures were more than offset in the electric utility industry by steady improvements in power technology, the economies arising from consolidating and interconnecting systems, and the economies of

AVERAGE PRICE OF ELECTRICITY TO ULTIMATE CONSUMERS

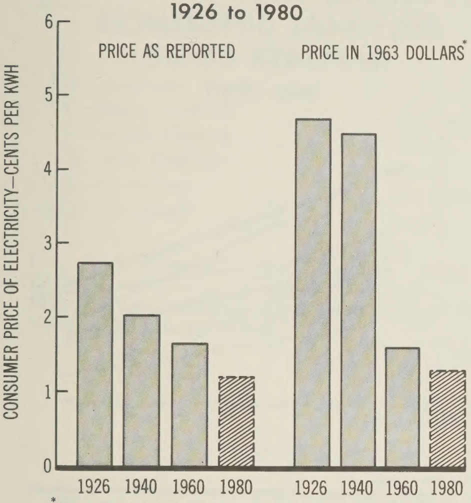
In Actual and 1963 Dollars

1926–1963



*Average Price to Ultimate Consumers in Actual Dollars, Divided by Consumer Price Index

FIGURE 139



ACTUAL AND PROJECTED CHANGES IN AVERAGE PRICE OF ELECTRICITY TO ULTIMATE CONSUMERS
1926 to 1980

*Price as Reported, Divided by Consumer Price Index, Which is Projected to 1980 Without Change.

Figure 140

scale accompanying the rapid growth of customer loads. The electric utility industry is less sensitive than most industries to general inflationary pressures, because its total costs include a much larger component of fixed charges. Thus, price changes in plant and equipment are not immediately reflected in utility costs, because plant and equipment are generally carried in the rate base at their original cost.

The resistance of electric rates to inflation has beneficially affected the consumers' welfare since 1940 as well as the industry's ability to compete and grow. Moreover, the importance of competitive factors such as private generation and the aggressive marketing programs of the natural gas and oil industries, and also indirect competition (by comparison) between segments of the electric industry itself and within segments, cannot be overlooked. The fact that the industry provides only a single product or service even though under varying cost conditions leads inevitably to intra-industry comparisons which serve as a spur to management.

In order to give some indication of the significance of inflation on the price of electricity, particularly since 1940, for illustrative purposes we have adjusted the past trend of average unit prices of electricity for changes in the purchasing power of the dollar by dividing the actual prices by the Consumer Price Index. The result of that adjustment is shown by the line labeled "Price in 1963 Dollars" in figure 139. The adjusted series provides a rough measure of the change in the "constant dollar" average cost of electricity per kwh over a broad sweep of years.

As illustrated in figure 140, a kilowatt-hour of electricity in 1926 cost about 4.7 cents in terms of 1963 dollars, compared with an actual figure of about 2.70 cents.

By 1940, following a deflationary period, the price per kilowatt-hour in 1963 dollars had declined to 4.50 cents, a reduction of less than 5 percent, although the actual decline, unadjusted for change in purchasing power, was almost 25 percent. The difference in values reflects the decrease in the general price level (i.e., the rise in the purchasing power of the dollar) during the 1930's.

From 1940 to the present, on the other hand, the decline in price per kilowatt-hour expressed in 1963 dollars was about 60 percent, although in actual dollars the decline was only about 20 percent. The 60 percent figure probably overstates the reduction since 1940 because all of the effects of the inflation of the 1950's have not yet been experienced and reflected in the rate structure. On the other hand, the actual price decline of 20 percent in the face of a substantial amount of inflation since 1940 grossly understates the effective reduction in price to the consumer.

The suggested target represents a 27 percent reduction in price per kilowatt-hour by 1980—larger than the 20 percent decline since 1940. However, it is misleading to compare the recorded 20 percent decline in the price per kilowatt-hour during the inflationary period since 1940 with the projected 27 percent reduction by 1980. We are not reflecting any inflation in our target for 1980 so that when the large inflation in the 1940 to 1960 period is considered, we are assuming an appreciably slower pace of reduction in terms of "constant dollar" prices between now and 1980 than that experienced since 1940, and slightly slower than that since 1950. It should be noted that the projected growth in annual electricity use from 1960 to 1980 is somewhat smaller in percentage terms than the actual growth rate from 1940 to 1960.

Projected Power Costs by Regions—1980

At present there are large differentials among the various regions in the average cost of power. This is apparent from table 73, which shows the actual average price of power in each Region in 1962 and our estimates of the attainable prices in 1980. As of 1962, the price was lowest, at 0.87 cents per kilowatt-hour, in Region VII (encompassing chiefly Washington, Oregon, Idaho, Utah and most of Montana). This area benefits from an abundance of low-cost hydroelectric resources, the advantages of which have been enhanced by large projects carrying low Federal and public fixed charge rates, and by a high average usage per customer. The highest prices of 2.18 cents, 2.16 cents and 2.15 cents respectively were in Region IV (broadly encompassing the states of Wisconsin, Illinois, Minnesota, Iowa, and a large part of Missouri), Region I (covering New England, New York, New Jersey, Delaware, and most of Pennsylvania and Maryland) and Region VI (Colorado, Nebraska, North and South Dakota and Wyoming) all of which have relatively low customer usage.

Our target estimates for the different regions imply a considerable narrowing of these differentials by 1980, as illustrated in figure 141. Reductions are projected for every region, but the largest percentage reduction is projected for Region IV, now the highest cost power area. Reductions of 30 percent or more are also shown for Regions I, V, and VI which have above-average costs. Virtually no change in unit cost is shown for Region VII. This is attributable in part to the low present base which does not permit the same scope for future improvement as in the higher cost areas, as well as to the lessening availability of highly economical hydroelectric sites in the region and the necessity for growing dependence on thermal generation in the late 1970's. Nevertheless due to its low rate level, use per customer in this region is expected to increase by a larger number of kilowatt-hours than in the other regions.

These projected reductions in the price of electricity are based in part on reduced costs of fuel transportation and more transmission interconnections, making it possible to have broader distribution of low-cost power. However, a major contributing factor is the substantial increase projected in customer usage. Increases in the number of customers and average use per customer for the eight FPC Statistical Regions are summarized in table 74 which indicates that the greatest *percentage* increases in use per customer are expected to occur in Regions V and VI.

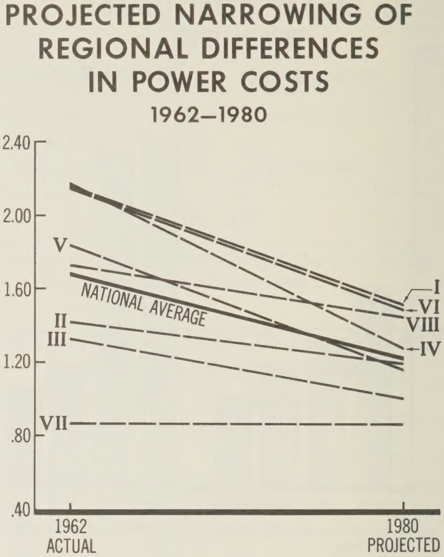
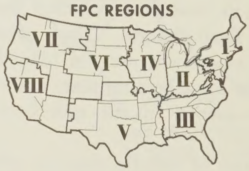


FIGURE 141



A comparison of Table 74 with Figure 141 shows that the trend toward gradual convergence of unit costs among the eight regions will be accompanied by a similar trend toward uniformity in usage per customer. Taken together, the similarity of these two trends is important evidence of the interdependence of electric price levels and growth.

TABLE 73

Price of Electricty by Region[1]

Cents Per Kilowatt-hour

Region	1962 Actual	1980 Projected	Percentage reduction
I—Northeast	2.16	1.51	30
II—East Central	1.42	1.19	16
III—Southeast	1.33	1.00	25
IV—North Central	2.18	1.27	42
V—South Central	1.84	1.16	37
VI—West Central	2.15	1.48	31
VII—Northwest	0.87	0.86	1
VIII—Southwest	1.73	1.44	17
U.S. Average[2]	1.68	1.23	27

[1] Average price per kilowatt-hour sold to ultimate consumers.

[2] Excludes Alaska and Hawaii.

TABLE 74

Regional Projections of Electricity Use
1962 Actual—1980 Projected

FPC statistical region	Sales to ultimate customers (billion kwh)		Number of customers (millions)		Average annual use per customer[1] (thousand kwh)		Percentage increase
					Actual	Projected	
	1962	*1980*	*1962*	*1980*	*1962*	*1980*	*1962-1980*
I—Northeast	152	427	15.5	20.9	9.8	20.4	108
II—East Central[2]	147	410	10.4	13.5	14.1	30.4	116
III—Southeast[2]	151	497	9.0	13.8	16.8	36.0	114
IV—North Central[2]	92	273	8.3	10.3	11.1	26.5	139
V—South Central	84	304	7.3	10.3	11.5	29.5	157
VI—West Central	16	57	1.8	2.4	8.9	23.8	167
VII—Northwest	61	201	2.5	4.0	24.4	50.2	106
VIII—Southwest	77	264	6.3	11.6	12.2	22.8	87
Total U.S.[3]	780	2,433	61.1	86.8	12.8	28.0	119

[1] All customers including industrial. Not to be confused with data on average residential use. For projected growth in residential use, see p. 42.

[2] Includes effect of large AEC diffusion plant loads.

[3] Excludes Alaska and Hawaii.

Fiscal Assumptions

By expressing the 1980 target in terms of 1963 dollars, we gain the advantage of a consistent purchasing-power standard for comparing present and projected future costs. However, the cost projections assume that the prices of fuels, equipment, right-of-way, and other cost elements will vary in accordance with expected market developments and technological improvements, but consistent with the stable price-level assumption for the economy as a whole. For instance, the cost estimates allow for a rising cost trend for rights-of-way and local taxes.

and a mixture of stable and falling prices for fuels and various kinds of equipment.

The 1980 estimates are based on the present overall cost of capital to the electric utility industry, but reflect a slight downward adjustment to take account of the income tax savings and slightly lowered cost of capital expected to result from moderately higher proportions of debt in the capital structure of investor-owned utilities. This adjustment was made because of the increased stability of utility earnings that may be expected with high-level coordination and a consequent pooling of investment risks.

The fixed charge rates used in the forecasts recognize existing regional variations in utility plant ownership. For each regional cost analysis, weighted averages reflecting ownership were computed for the various categories of equipment investments. The derivation and magnitude of these charges are presented in more detail in the section that follows. This general approach to fixed charges is in line with the arbitrary assumption (not a prediction) that there will be no change in each industry segment's share of the total electric utility investment in that region. Underlying this assumption is the view that the relative growth of the various segments of the industry depends upon developments outside the scope of the National Power Survey.

Fixed Charges

Electric power costs are usually estimated in terms of their fixed and variable components. Fixed costs consist of annual fixed charges and other cost components which are essentially unaffected by output, i.e., the number of kilowatt-hours generated. Fixed charges are generally considered to include cost of money, depreciation (or amortization), interim replacements, insurance, and property taxes. These elements may all be related to total (gross) investment in utility plant including generating, transmission and distribution facilities. Although income taxes may vary with the extent the plant is used, they are also generally included as fixed charges in the case of public utilities, because they are reasonably predictable and the courts have held that the constitutional return which a utility is entitled to earn must be computed after allowance for such taxes. The variable costs are principally those associated with the amount of generation such as fuel, payroll labor, and other operating and maintenance expenses.

For the purpose of considering alternative means of performing a needed function, cost estimates have been based on uniform average fixed charges as shown in table 75, with one exception. The exception is that multiple-purpose hydroelectric projects were also examined under criteria established for federal agency use in project formulation and justification.

The fixed charges differ for various types of equipment primarily by reason of the difference in service lives. All are based on an industrywide weighted cost of money and taxes.

The uniform fixed charges are based on the present segmental composition of the industry. As of 1962 the gross investment in electric utilities was as follows:

Private ownership	76%
Federal (TVA, 6%; other, 7%)	13
Cooperatives	1
Non-Federal Public	10
Total	100%

For the purpose of making a more meaningful estimate of the cost of power in 1980 by FPC regions, a more precise method was required to recognize the marked difference in the amount of publicly owned electric power facilities in the various regions. The fixed charges, adjusted by regions, are set forth in detail in table 76. They are equivalent in the composite to the nation-wide uniform fixed charges.

The influence of the public and federal ownership on the fixed charges for some of the components is pronounced. For example, the 8.5 percent fixed charge for the hydro component of Region I reflects the large investments of the New York State Power Authority in its hydroelectric facilities at Niagara and on the St. Lawrence River at Massena, New York. Similarly the 10 percent fixed charge for steam generating plants in Region VI results from the all inclusive public power systems of Nebraska and the several municipal plants in the Region.

The 11 percent for steam plants in Region III reflects the Tennessee Valley Authority's steam generating capacity as a sizeable part of the whole and also some other municipal, district and REA financed steam projects.

The 5.5 percent for hydro in Region V and the 6.0 percent in Region VII reflects the predomi-

TABLE 75

U.S. Average Fixed Charge Rates for Electric Power Systems (Percent)

	Generating Investment					Transmission Investment			Distribution Investment
	Conventional Steam		Nuclear Steam, 30 Yr Life	Hydro-electric, 75 Yr Life	Int. Comb. and Gas Turbine, 35 Yr Life	Sub-stations, 35 Yr Life	Wood Pole, 35 Yr Life	Steel Tower, 50 Yr Life	Composite Property, 32 Yr Life
	30 Yr Life	35 Yr Life							
Cost of Money	5. 5	5. 5	5. 5	5. 5	5. 5	5. 5	5. 5	5. 5	5. 5
Depreciation/Amortization	1. 4	1. 0	1. 4	0. 1	1. 0	1. 0	1. 0	0. 4	1. 2
Interim Replacements	0. 4	0. 4	0. 7	0. 1	0. 4	0. 4	0. 2	0. 1	0. 4
Insurance	0. 3	0. 3	0. 8	0. 1	0. 3	0. 3	0. 1	0. 1	0. 3
Taxes:									
Federal Income Tax	2. 5	2. 5	2. 5	2. 5	2. 5	2. 5	2. 5	2. 5	2. 5
Other Taxes	1. 9	1. 9	1. 9	1. 9	1. 9	1. 9	1. 9	1. 9	1. 9
Total	12. 0	11. 6	12. 8	10. 2	11. 6	11. 6	11. 2	10. 5	11. 8
Rounded Figures for use in NPS	12. 0	11. 5	13. 0	10. 0	11. 5	11. 5	11. 0	10. 5	12. 0

nating influence of federally financed projects in Region V and a combination of Federal and other publicly financed projects in Region VII.

The difference between the 12.0 percent U.S. average fixed charge for distribution and the 8 percent in Region VI, the 8.5 percent in Region VII and 10.0 percent in Region III reflects the substantial investment in the several publicly owned distribution systems in these Regions. Conversely the 13.0 percent fixed charges for Regions I and II reflect the relatively small investment in publicly-owned distribution systems in these two regions.

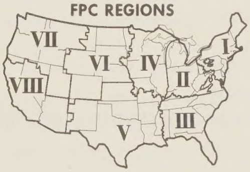


TABLE 76

1980 Regional Composite Fixed Charges for Electric Power Systems (Percent)

Composite Fixed Charges	Federal Power Commission Statistical Region							
	I	II	III	IV	V	VI	VII	VIII
(1) Production Plant:								
Steam [1]	13. 0	12. 5	11. 0	12. 0	11. 5	10. 0	12. 0	12. 0
Nuclear	14. 0	13. 5	12. 0	13. 0	12. 5	11. 0	13. 0	13. 0
I.C. and Gas Turbine	13. 0	12. 5	12. 0	10. 0	9. 5	9. 0	9. 0	11. 0
Hydroelectric	8. 5	11. 5	8. 0	12. 0	5. 5	8. 0	6. 0	8. 0
(2) Transmission [2]	11. 0	11. 0	9. 5	10. 5	10. 5	9. 0	9. 0	10. 5
(3) Distribution	13. 0	13. 0	10. 0	12. 0	11. 0	8. 0	8. 5	11. 5

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[1] Values based on weighted average of 30 and 35 year life, Table 75.

[2] Values based on weighted component of lines and substations, Table 75.

Composition of Power Costs

Table 77 presents in detail some of the supporting elements for the 1962 and 1980 power cost components which were summarized in table 72 and additional data on usage and investments which may be helpful in understanding the relative magnitudes of the reductions summarized in tables 78 and 79.

Total 1980 production costs are expected to be 2.3 times those of 1962. However, 1980 sales are expected to increase 3.1 times—from 780 billion kwh in 1962 to 2,433 billion kwh in 1980. Consequently, average production costs per kwh will decline from 8.5 to 6.3 mills per kwh. Half of this reduction (1.1 mills) is in fixed charges on investment in generating equipment, fuel accounts for 32 percent, and operation and maintenance accounts for the remainder at 18 percent. These savings are expected to come about as a result of coordinated planning to take advantage of load diversity, reduc-

TABLE 77

Composition of Total Cost of Electric Power—Total Industry—1962 Actual and 1980 Estimated

	1962 actual		1980 estimated	
	Total (billions)	Per kwh sold	Total (billions)	Per kwh sold
Production costs (including imports):				
Operation and maintenance expenses (except fuel)[1]	$1. 0	0. 13¢	$2. 1	0. 09¢
Fuel expenses	1. 9	. 24	4. 2	. 17
Fixed charges [2]	3. 7	. 48	8. 9	. 37
Total production costs	6. 6	. 85	15. 2	. 63
Transmission costs:				
Operation and maintenance expenses	0. 3	. 04	0. 5	. 02
Fixed charges	1. 0	. 13	3. 6	. 15
Total transmission costs	1. 3	. 17	4. 1	. 17
Distribution costs:				
Operation and maintenance expenses	2. 4	. 31	3. 9	. 16
Fixed charges	2. 7	. 35	6. 7	. 27
Total distribution costs	5. 1	. 66	10. 6	. 43
Total cost of power:[3]	$13. 0	1. 68¢	$29. 9	1. 23¢
Sales to ultimate consumers—billions of kwh	773. 7		2, 433. 0	
Number of customers—millions [4]	60. 6		86. 8	
Average kilowatt-hours per customer	12, 768		28, 030	
Total undepreciated investment in electric utility plant—billions	$66. 1		$172. 7	
Total investment per customer	$1, 091		$1, 990	
Distribution investment per customer	$404		$630	

[1] Operation and maintenance expenses include allocated administrative and general expenses.

[2] Fixed charges as used herein include cost of money (return on investment), depreciation and amortization and all taxes including payments made in lieu of taxes. Fixed charges on general plant were allocated to "Production," "Transmission" and "Distribution."

[3] Total electric revenues from ultimate customers.

[4] Average for year.

tion in reserve capacity, the use of larger and more efficient generating units, lower fuel prices resulting from more efficient coal mining methods, lower costs for large bulk movements of fuel, and the introduction of nuclear power.

No change is estimated in the unit cost of transmission, because the total investment in transmission facilities is expected to expand nearly in proportion to the projected increase in power sales.

The size of the reduction foreseen in unit cost of distribution in the period to 1980 may be surprising to many. Annual costs are estimated to increase a little more than twice, but with sales increasing 3.1 times, we expect the distribution cost per kwh to decrease from 6.6 mills to 4.3 mills per kwh, or 35 percent. This reduction accounts for about 50 percent of the estimated reduction in 1980 power costs. To realize it will require an aggressive program to increase power use by all classes of customers. Capital investment in distribution facilities must inevitably increase, not only by reason of increased usage and the equipment needed to meet this increase, but also because of rising public demand for improved appearance in the urban environment which will require increasing use of underground distribution and other expenditures for amenity purposes. Thus, investment in distribution facilities is expected to increase from $404 per customer in 1962 to about $630 in 1980. However, per customer usage is expected to increase at an even greater rate, from 12,768 kwh in 1962 to 28,030 kwh in 1980.

Evaluation of Sources of Cost Savings

The projected unit cost of power in 1980 of 1.23 cents per kwh is 0.45 cents less than the 1962 average cost of 1.68 cents per kwh. This differential, applied to total estimated sales in 1980 of 2.4 trillion kwh, represents a gross reduction of $11 billion a year as compared with the estimated 1980 sales at the 1962 average cost per kwh.

Before proceeding to examine the separate sources, as summarized in table 79, which contribute to the total annual saving of $11 billion, it will be helpful to review the projected net reductions in power system investment in 1980 as compared with the investment which would be required under 1962 conditions, assuming a constant dollar value. These reductions are summarized in table 78. The total of the investment savings is $11.7 billion, which is derived from the gross savings of $14.83 billion resulting from capacity reductions and lower unit costs of capacity additions between 1965 and 1980, less the investment increases, mostly for transmission, amounting to $3.13 billion.

The savings in investment costs thus determined are converted to annual savings by application of an average fixed charge of 12 percent. The resulting reduction of $1.40 billion appears as the first item in table 79. The next three items in the table relate to fuel cost savings and total $2.10 billion annually. These are followed by several smaller savings including reduced spinning reserve, greater use of secondary hydroelectric energy and broader economy energy exchanges, totalling $0.11 billion. Reduced operating and maintenance expense for production and transmission is a major item amounting to $1.46 billion and results largely from the growth in sales, particularly in relation to use per customer. The magnitude of the saving per kilowatt-hour is given in table 77. By far the largest single item of reduced cost is related to distribution, amounting to $5.60 billion. Table 77 shows the large reductions in the components of the unit costs for distribution, for operation and maintenance and to a lesser degree for fixed charges. The concluding two items in table 79 pertain to fiscal reductions and include a $300 million saving in the cost of money and a $370 million reduction in Federal income taxes reflecting the recent cutback from 52 percent to 48 percent of net taxable income.

A major part of the cost reduction anticipated by 1980 is represented by savings in the distribution function. These are expected to account for 50 percent of the total savings possible by 1980. While opportunities are numerous in the distribution area for introducing improved operation and maintenance programs, and while new business methods and improved facilities will aid in lowering costs, substantial unit cost reductions in distribution, more than any other area, are dependent on load growth. This is true because the costs of connecting the customer and reading his meter, operating and maintaining the local distribution system, and performing the business operations, are affected very little by a doubling or tripling of customer usage, and many distribution facilities can deliver additional power at small incremental increases in cost. Thus a doubling in the amount of power consumed per customer, as the survey has forecast, will appreciably lower the average distribution unit cost of power

TABLE 78

Estimated Reduction in Power System Investment by 1980 as Compared With Investment Required for the Same Capacity Under 1962 Conditions

Reduction in Capital Investment	
(1) *Reserve capacity reductions* Reserve savings attainable by 1980 through increased interconnection and coordination are estimated at 50 million kw (See chapter 14).	$6, 700, 000, 000
(2) *Capacity reduction through load diversity* Usable diversity savings allowing for increase in scheduled maintenance are estimated to reach 30 million kw by 1980 (See Chapter 13).	4, 300, 000, 000
(3) *Use of larger fossil fuel steam-electric units* Fossil fuel fired steam-electric capacity additions are estimated at about 175 million kw in the period from 1965 to 1980. The projected larger sizes in this period are estimated to result in an average saving of $20 per kw of capacity by comparison with average sizes of base load units now installed.	3, 500, 000, 000
(4) *Use of larger units—nuclear* Nuclear steam-electric capacity additions are estimated at 68 million kw in the period from 1965 to 1980. The projected larger sizes in this period are estimated to result in an average saving of about $5 per kw of capacity by comparison with average sizes of base load units now installed.	330, 000, 000
Total estimated gross reduction	14, 830, 000, 000
Increase in Capital Investments	
(5) *Added EHV transmission investment* This is the estimated cost of the long distance EHV transmission lines depicted in the general transmission pattern in Chapter 15.	$3, 100, 000, 000
(6) *Added investment in inter-system communications* Includes only communication and coordination costs in excess of those required for normal system growth. Does not envision centralized load dispatching. Such added costs have been found to be on the order of one percent of the cost of major interconnecting transmission facilities (item 5 above).	30, 000, 000
Total estimated gross increase	3, 130, 000, 000
Net reduction in capital investment	$11, 700, 000, 000

by 1980, even in the face of considerably increased investment in distribution facilities.

Growth in electric energy use is not readily separable from other factors which have a bearing on reductions in cost, because growth is both the result and cause of future economies. In fact, the price-growth spiral which can produce lower costs and greater output is an outstanding characteristic of the electric utility industry. Maximum growth in electric consumption will only occur if electric rates are lowered as fast as cost reductions will permit, while such reductions will themselves depend in large part upon the extent of growth. If rates could be reduced to a level consistent with the cost reduction which might ultimately result from the engendered growth, increased usage beyond that predicted could be confidently expected.

Indeed growth is the predominant parent event which makes it profitable and necessary to employ in increasingly greater scope the economies that are examined in this Survey. The use of larger generating units, the more numerous and stronger system interconnections, the use of higher transmission voltages, the exchange of diversity between

TABLE 79

Estimated Reduction in Annual Power Costs by 1980

(1)	*Reduced Capital Investment* As indicated in table 78, the net saving in generating and transmission plant investment is estimated to be $11.7 billion to which an average fixed charge of 12 percent has been applied.	$1,400,000,000
(2)	*Fuel Cost Savings through Increased Thermal Efficiency* The estimate reflects an expected improvement in the efficiency of fossil fuel plants, from an average heat rate of 10,600 Btu required to generate a kwh of electricity in 1962, to 8,900 Btu by 1980.	800,000,000
(3)	*Fuel Cost Savings through Increased Use of Nuclear Power* This item is based on saving 1.0 mills per kwh on the estimated total nuclear generation in 1980.	500,000,000
(4)	*Fuel Cost Savings through Mining and Transportation Improvements* This figure is based on a total average decrease between 1960 and 1980 of five cents per million Btu in the delivered cost of fuel applied to the estimated 1980 production of 1.8 trillion kwh from coal fired plants at an average heat rate of 8,900 Btu by 1980.	800,000,000
(5)	*Savings from Reduced Spinning Reserve* This item results from the opportunity to save on the average amount of capacity maintained in spinning reserve status because of increased interconnection. The unit saving is limited to fuel and operating expenses of about $2.50 per kilowatt per year. This unit saving is applied to a potential reduction in spinning capacity from 7.5 percent of load down to about 5 percent of load, or 12,000,000 kilowatts.	30,000,000
(6)	*Reduced Cost of Fuel through Greater Use of Secondary Hydroelectric Power* The amount shown results from the expected increased use of secondary power by 1980, principally involving the Pacific Northwest and the Pacific Southwest (Areas P and N).	10,000,000
(7)	*Reduced Cost of Fuel through Broader Economy Energy Exchange* This estimate reflects the broader availability of low cost energy from efficient thermal sources. The incremental exchange has been taken as eight percent of the capacity of such sources evaluated at 0.5 mills per kwh.	70,000,000
(8)	*Reduced Operating and Maintenance Expenses for Production and Transmission (including apportionments of administrative and general expenses)* Contributed through growth in sales, particularly in relation to use per customer, and through increase in size of generating and transmission facilities.	1,460,000,000
(9)	*Reduced Distribution Costs (including certain apportionments of general expenses and taxes)* This lowering of distribution costs is based on large reduction in investment costs and concomitant reductions in operating expenses per kwh of sales resulting from increased customer usage and number of customers. (See table 77)	5,600,000,000
(10)	*Reduced Cost of Money* This item is based on an increase in debt financing of the private utility segment from about 52 percent of total capitalization to 60 percent, with resulting savings both in direct cost of money and in income taxes.	300,000,000
(11)	*Reduction in Federal Income Tax* The determination is based on applying the reduction from 52 percent to 48 percent (of net taxable income) to the projected revenues of 1980 for the private utility segment.	370,000,000
	Total annual saving	11,340,000,000
	In round figures	11,000,000,000

areas and regions, and even the linking of systems to save reserve capacity, are all intimately associated with load growth.

The costs of distributing power, as we have seen, are especially affected by growth, particularly by growth in use per customer.

The potential savings in the production area (roughly 50 percent of the total) have been the principal subject of analysis of this survey. These savings, which encompass the first seven items in table 79, will be influenced by the industry's success in further developing and expanding intersystem planning and operation. While coordination obviously is dependent upon load growth to become as effective as it is shown to be in the analysis, the load growth projected herein is in turn dependent upon the economics of coordination, and other economies also, to provide lower electric rates and thus help the electric industry compete for new loads.

Improved technology will of course enhance the advantages of more complete coordination and open new opportunities for coordination over longer distances and at higher voltages. The technological advances built into the 1980 target, however, are not limited to progress which will come easily from the momentum the industry has already achieved. Our assumptions as to future technology anticipate a continued aggressive, systematic research and development attack on major technological problems by all parts of the industry, acting both cooperatively and individually on their own initiative. Although the technological research and development program of the electric utility industry cost over $50 millions in 1963, it is assumed that the promise of further benefits will spur the industry to adopt even more effective future programs involving substantially larger sums.

The history of the industry is one of imagination and progress, particularly in connection with the continued improvement in the art of electric generation and transmission, but there remains great incentive for further research in all areas, and particularly the field of distribution and in the development of the new customer appliances needed if the 1980 growth projections are to be reached. These improvements will require cooperative research efforts embracing all segments of the industry (including the equipment manufacturers) and all sizes of utility, large and small. The benefits of such a vigorous research and development program are necessary to offset the possible added costs of underground distribution, urban and suburban rights-of-way, control of air and water pollution, increased property tax rates and similar factors resulting in part from increased urbanization.

Summary

The average retail price for electricity is expected to decline 27 percent by 1980—from 1.68¢ per kilowatt-hour in 1962 to 1.23¢ in 1980, assuming no further price inflation. This reduction of roughly half a cent (0.45¢) per kilowatt-hour presumes further great growth in electric use. The savings in 1980 are divided fairly evenly between production and distribution, the former accounting for twenty-two hundredths of a cent and the latter for twenty-three hundredths of a cent per kilowatt hour sold (in figures—.22¢ and .23¢). Applying these estimates to projected 1980 sales of 2.43 trillion kilowatt-hours indicates annual savings as follows:

	Billion
Production (generation)	$5.4
Transmission	0.0
Distribution	5.6
Total	$11.0

If the dollar declines in value between now and 1980, the estimated cost reduction in terms of 1980 dollars would be smaller than the 27 percent indicated.

The Commission makes no claim that the patterns and guidelines that have been presented are an optimization of power planning for meeting future loads. However, we believe they represent a reasonable approach toward achieving further economy in the nation's power supply. To the extent they may be less than an optimum, the potential savings we have estimated may be understated. Our judgment is supported by the fact that the present trends in the electric power industry are in the directions we project and the approaches we advocate are being actively espoused by many industry leaders.

It is hoped that this Survey will serve to accelerate interest in more comprehensive industry planning and will direct the attention of all systems in every segment of the industry to the attainable levels of achievement and the relative significance of the various avenues for realizing economic gains for their systems and their customers.

NATIONAL POWER SURVEY GLOSSARY

Term	*Definition*
alternating current (AC)	An electric current that reverses its direction at regular intervals.
ambient temperature	Temperature of the surrounding cooling medium, such as gas or liquid, which comes into contact with the heated parts of the apparatus.
anadromous fish	Fish, such as salmon, which ascend rivers from the sea at certain seasons to spawn.
backbone transmission system	The principal portion of a transmission system to which other lines connect.
back-up	Reserve generating capacity of a power system.
base load	The minimum load over a given period of time.
breeder reactor	A nuclear reactor capable of producing more nuclear fuel than it consumes.
Btu	British thermal unit. A measure of heat energy. The quantity of heat energy required to raise the temperature of 1 pound of water 1 degree Fahrenheit, at sea level.
bulk delivery point	A substation which receives power delivered at high voltage. Transformers at these points lower the voltage for power distribution.
busbar	An electrical conductor in the form of rigid bars, located in switchyard or power plants, serving as a common connection for two or more electrical circuits.
capacitor	A dielectric device which momentarily absorbs and stores electrical energy.
capacity	The maximum power output or load for which a machine, apparatus, station or system is rated.
capacity interchange	In power pooling, transactions resulting from the assignment by participating utilities of reserve or excess generating capacity for common use.
central station service	Refers to electric service supplied from an electric system rather than by self-generation.
circuit breaker	A switch that automatically opens an electric circuit carrying power when an abnormal condition occurs.
coal slurry pipeline	A pipeline which transports coal in pulverized form suspended in water.
coincident demand	Any demand that occurs simultaneously with any other demand; also the sum of any set of coincident demands.
condenser	In a steam electric plant, a device which condenses steam into water after the steam has gone through the turbine before it is injected into the boiler for reuse.
connected load	The sum of the capacities of the electric power consuming devices connected to a supplying system.
coordination	Cooperative action by two or more systems to achieve the economies of overall power supply and network integration.
critical (as related to nuclear material)	The condition whereby an atomic chain reaction is capable of being sustained in a nuclear reactor.
critical streamflow	The amount of water available for hydroelectric power generation during the most adverse streamflow period.
desalination plant	A water supply plant which removes salt from sea water or brackish water to produce potable water.
direct current (DC)	An electric current which always flows in one direction but may vary in magnitude.
dispatching	The operating control of generating units and transmission lines of an integrated electric system including assigning of generator outputs as needed, controlling maintenance and switching operations, and scheduling energy transactions with connected utilities.
diversity	The differences among individual electric loads resulting from the fact that the maximum demands of customers do not all occur at the same time.
economy energy	Energy produced and supplied from a more economical source, substituted for energy that could have been produced by a less economical source.
EHV	Extra High Voltage, usually used to refer to voltages of more than 230 kilovolts.
energy	That which does or is capable of doing work, and is equal to average power multiplied by the interval of time.
energy requirements	The amount of electric energy needed by a utility to serve its customers and to cover system losses.

firm power	Power intended to have assured availability to the customer to meet his load requirements.
fission	The release of energy through the process whereby the nucleus of an element captures a neutron and splits into two nuclei of lighter elements.
forced outage	The shutting down of a generating unit for emergency reasons.
fossil fuels	Refers to coal, oil, and natural gas.
Francis-type unit	A hydraulic turbine using vanes to drive generating equipment. Water enters the unit at a right angle.
fusion	The combining of atomic nuclei of very light elements by collision at high speed to form new and heavier elements, resulting in the release of energy.
gaseous diffusion	A method of isotope separation used to enrich uranium with the uranium-235 isotope. Based on the fact that atoms or molecules of different masses will diffuse through a porous barrier at different rates.
generator, electric	A machine which converts mechanical energy into electric energy.
Gross National Product (GNP)	The Nation's total national output of goods and services at current market prices.
G&T Cooperatives	Electric utility cooperatives which generate and transmit electric power usually at wholesale to distribution cooperatives and other member systems.
gigawatt (gw)	One million kilowatts.
head, gross	The difference of elevation between the headwater surface above and the tailwater surface below a hydroelectric power plant, under specified conditions.
heat rate	A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned or of heat released from a nuclear reactor by the resulting net kilowatt-hour generation.
heavy water	Water used in the moderation of nuclear reaction by certain types of atomic power plants. In this water (D_2O), the hydrogen of the water molecule consists entirely of deuterium—the heavy hydrogen isotope of mass 2.
holding company	A nonoperating company which controls other companies through stock ownership.
hydroelectric plant	An electric power plant in which the generators are driven by falling water.
interconnection	A transmission line joining two or more power systems through which power produced by one can be used by the other. Also—intertie.
integral train	Similar to unit train except that the cars are permanently coupled.
intertie	See interconnection.
Kaplan unit	A hydraulic turbine using propellor-shaped blades, which are adjustable under load, to drive generating equipment.
kilovolt (kv)	One thousand volts.
kilowatt (kw)	One thousand watts.
kilowatt-hour (kwh)	A unit of energy equal to the work done by one kilowatt acting for one hour.
lignite	A low grade coal of a variety intermediate between peat and bituminous coal.
line compensation	The balancing out of line impedance.
line impedance	The apparent opposition to the flow of alternating current that is analogous to the actual electrical resistance to a direct current.
load	The amount of power needed to be delivered at a given point on an electric system.
load center	The point at which the loads of a given area are assumed to be concentrated for purposes of analysis.
load diversity	The difference between the sum of two or more individual peak loads and the coincident or combined maximum load, usually measured in power units.
load factor	The ratio of the average load supplied during a designated period to the peak or maximum load occurring in the same period.
load growth	The growth in energy and power demands by a utility's customers.
margin	The difference between the net system generating capability and system maximum load requirements including net schedule transfers with other systems.
mine-mouth steam-electric	A steam-electric plant built close to coal mines and usually associated with delivery of output via transmission lines over long distances as contrasted with plants located nearer load centers and at some distance from sources of fuel supply.
multi-purpose river basin program	Programs for the development of rivers with dams and related structures which serve more than one of different purposes, such as—hydroelectric power generation, navigation, flood control, recreation, irrigation, water supply, water quality control, and fish and wildlife enhancement.

multi-purpose transmission line	Employment of a transmission line for more than one function, such as regular transmission, wheeling, reserve capacity, and peak capacity usage.
megawatt (mw)	One million watts or one thousand kilowatts.
nuclear energy	Energy produced largely in the form of heat during the fission process in a nuclear reactor, which, with conventional generating equipment can be transformed into electric energy.
nuclear power	Power released from the heat of nuclear reactions, which is converted to electric power by a turbine-generator unit.
nuclear reactor	An apparatus in which nuclear fission is achieved in a self-sustained chain reaction.
outage	The period in which a generating unit, transmission line, or other facility, is out of service.
(in) parallel	Several units whose AC frequencies are exactly equal, operating in synchronism as part of the same electric system.
particulate matter	Solid particles, such as ash, which are released from combustion process in exhaust gases at fossil-fuel plants.
peak load	The greatest amount of all of the power loads on a system, or part thereof, which has occurred at one specified period of time.
peaking capacity	That part of a system's generating equipment which is operated only intermittently for short periods during the hours of highest power demand.
pondage	The amount of water stored behind a hydroelectric dam of relatively small storage capacity used for daily or weekly control of the flow of a river.
power (electric)	The rate of generation or use of electric energy, usually measured in kilowatts.
power factor	The percentage ratio of the amount of power, measured in kilowatts, used by a consuming electric facility to the apparent power measured in kilovolt-amperes.
power pool	Two or more electric systems which are interconnected and coordinated to a greater or lesser degree to supply, in the most economical manner, electric power for their combined loads.
preference customers	Publicly-owned systems and nonprofit cooperatives which by law have preference over investor-owned systems for the purchase of power from Federal projects.
prime mover	The engine, turbine, water wheel, or similar machine which drives an electric generator.
psi	Pounds per square inch.
pumped storage	An arrangement whereby electric power is generated during peak load periods by using water previously pumped into a storage reservoir during off-peak periods.
Q	The equivalent to 1 billion billion Btu's, the heat content of about 40 billion tons of high-grade coal.
reaeration	The process whereby the oxygen content of water which has been depleted by heat from thermal power plants or by a deep position in a reservoir or otherwise is restored to normal level.
reserve generating capacity	Extra capacity maintained to generate power in the event of unusually high demand or a loss or scheduled outage of regular generating capacity.
residual fuel oil	Oil remaining after the petroleum refining process is completed.
reverse-current relays	A sensing device (relay) used to actuate some other piece of equipment, such as a circuit breaker, when the power flow changes direction along a transmission line.
reversible capacity	A single machine which can be used alternately as a pump and a generator, and is therefore important for pumped storage developments.
seasonal diversity	Diversity between two (or more) power systems which occurs when their annual peak loads are in different seasons of the year.
secondary hydroelectric energy	Hydroelectric energy which is not available on a continuous basis under the most adverse hydraulic conditions contemplated.
series capacitors	A bank of capacitors connected in series with an electric power transmission line which are used to control the magnetic component of line impedance.
service outage	The shut-down of a generating unit, transmission line or other facility for inspection, maintenance, or repair.
shunt capacitors	Capacitors connecting from a power line to a grounded connection, usually designed to reduce that part of the electric current causing a poor power factor.
spinning reserve	Generating units, operating at no load or at various outputs, with excess capacity ready to take on more load.
standby	Generating equipment that is not normally used but is available, through a permanent connection, to replace or supplement the usual source of supply.

steam-electric plant	A plant in which the prime movers connected to the generators are driven by steam.
surplus power	Generating capacity which is not needed on the system at the time it is available.
tap	A connection from one transmission line to another or to a substation.
thermal plant	A generating plant which uses heat to produce electricity. Such plants may burn coal, gas, oil, or use nuclear energy to produce the necessary thermal energy.
thermal pollution	Rise in water temperature of rivers from heat released by a thermal plant to water used for cooling, with resulting effects on other uses of the water.
tie-line	Transmission line connecting two systems.
time zone diversity	Diversity between systems in different time zones resulting from time difference as it affects the demands for power.
transformer	An electromagnetic device for changing the voltage of alternating current electricity.
turbine	The part of a generating unit which is spun by the force of water or steam to drive an electric generator. The turbine usually consists of a series of curved vanes or blades on a central spindle.
turn-key proposal	A job in which responsibility for all features of a complete development is undertaken by a single contractor.
unit train	An entire train used solely to transport coal directly from coal fields to a utility's steam generating plant.
vertically integrated system	Refers to power systems which combine generation, transmission and distribution functions.
voltage of a circuit	The electric potential difference between conductors or conductors to ground, usually expressed in volts or kilovolts.
wheeling	Transportation of electricity by a utility over its lines for another utility; also includes the receipt from and delivery to another system of like amounts but not necessarily the same energy.

Sources: (1) Glossary of Electric Utility Terms prepared by Edison Electric Institute 1961. Also EEI Nuclear Supplement (1961). (2) Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement 1949 (GPO). (Prepared by a Subcommittee on Glossary of the Federal Inter-Agency River Basin Committee). (3) FPC Staff. (4) Nuclear Terms: A Brief Glossary. U.S. Atomic Energy Commission 1964.

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Bureau of Power:

- Joseph J. A. Jessel, Chief, Division of Electric Resources and Requirements
- Warren C. Jackson, Chief, National Power Survey Section
- R. John Mather, National Power Survey Section
- Harold E. Roberts, National Power Survey Section
- Jerome K. Delson, National Power Survey Section
- Norman C. Nelson, Chief, Power Requirements and Supply Section
- James J. Stout, Chief, Division of River Basins

Other staff offices:

- S. David Freeman, Assistant to the Chairman
- William Iulo, Office of Economics
- William R. Hughes, Office of Economics
- Thomas M. Debevoise, Office of General Counsel

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Personal Services

Review of semi-final drafts of report:
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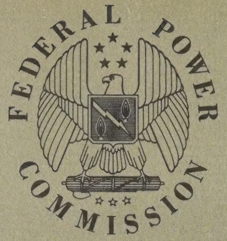

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